BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF OKLAHOMA GAS AND ELECTRIC COMPANY FOR AN EXPEDITED ORDER APPROVING A TEMPORARY SURCHARGE TO RECOVER THE COSTS OF A RENEWABLE WIND GENERATION FACILITY, A DECLARATORY RULING THAT CERTAIN RENEWABLE WIND GENERATION PURCHASE POWER AGREEMENTS ARE PRUDENT; AND A DETERMINATION THAT COST OF SUCH PURCHASE POWER AGREEMENTS ARE RECOVERABLE THROUGH THE ENERGY COST RECOVERY RIDER	)	DOCKET NO. 10-073-U

DIRECT TESTIMONY OF
J. RICHARD HORNBY
SYNAPSE ENERGY ECONOMICS, INC.

ON BEHALF OF THE
GENERAL STAFF OF THE
ARKANSAS PUBLIC SERVICE COMMISSION

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NOVEMBER 19, 2010

PUBLIC VERSION

Q. Please state your name, position and business address.

A. My name is J. Richard Hornby. I am a Senior Consultant at Synapse Energy Economics, 22 Pearl Street, Cambridge, MA 02139.

Q. On whose behalf are you testifying in this case?

A. I am testifying on behalf of the General Staff of the Arkansas Public Service Commission (General Staff).

Q. Please describe Synapse Energy Economics.

A. Synapse Energy Economics ("Synapse") is a research and consulting firm specializing in energy and environmental issues. Its primary focus is on electricity resource planning and regulation including computer modeling, service reliability, resource portfolios, financial and economic risks, transmission planning, renewable energy portfolio standards, energy efficiency, and ratemaking. Synapse works for a wide range of clients including attorneys general, offices of consumer advocates, public utility commissions, environmental groups, the U.S. Environmental Protection Agency, Department of Energy, Department of Justice, Federal Trade Commission and the National Association of Regulatory Utility Commissioners. Synapse has a professional staff of twenty-two with extensive experience in the electricity and natural gas industries.

Q. Please summarize your educational background.

A. I have a Bachelor of Industrial Engineering from the Technical University of Nova Scotia, now the School of Engineering at Dalhousie University and a Master of Science in Energy Technology and Policy from the Massachusetts Institute of Technology (MIT).

Q. Please summarize your professional experience.

A. I have worked in the energy industry since 1976 as a project engineer, a senior civil servant and a regulatory consultant. As a project engineer I was responsible for identifying and pursuing opportunities to reduce energy use in a factory in Nova Scotia. Subsequently, after my graduate program at MIT, I spent several years as a senior civil servant with the government in Nova Scotia where I helped prepare the province's first comprehensive energy plan and served on a federal-provincial board responsible for regulating exploration and development of offshore oil and gas reserves. Since 1986, as a regulatory consultant I have reviewed numerous integrated resource plans in the gas and electric industries, testifying extensively regarding cost allocation and rate design. During the past several years I have managed various projects to estimate the avoided costs of electricity and natural gas, reviewed the economics of demand response and smart grid proposals and testified regarding the alignment of utility financial incentives and rates with the pursuit of energy efficiency. I have provided expert testimony and litigation support on these issues in over 120 proceedings on behalf of utility regulators, consumer advocates, environmental groups, energy marketers, gas producers, and utilities.

Q. Have you prepared an exhibit summarizing your regulatory experience?

A. Yes. My regulatory experience is summarized in Exhibit JRH-1.

Q. What is the purpose of your testimony?

A. Oklahoma Gas and Electric Company (OG&E or Company) has requested approval of its acquisition of the OU Spirit Facility (OU Spirit), its purchase of wind energy under wind energy purchase agreements (WEPAs) with Keenan and Taloga, and rate recovery of the resulting revenue requirements and expenses. General Staff retained Synapse to assist in their review of OG&E's request. The purpose of my testimony is to address whether the OU Spirit project and the two WEPAs are in the public interest. General Staff Witness Regina L. Butler addresses the Company's proposal for rate recovery of the resulting revenue requirements and expenses.

Q. What data sources did you rely upon to prepare your review of OG&E's request?

A. My review began with the Direct Testimony and Exhibits of OG&E witnesses Donald R. Rowlett and Jesse B. Langston. I then reviewed their responses to information requests, as well as testimony and data responses from the Oklahoma Corporation Commission (OCC) proceedings regarding the Windspeed transmission line, OU Spirit, the Taloga WEPA, and the Keenan WEPA. In addition I reviewed various projections and reports regarding future prices for natural gas and carbon dioxide. Finally I reviewed Arkansas Public Service Commission (APSC) Order Nos. 6 and 7 in Docket No. 06-028-R[1] the provisions of Ark. Code Ann. § 23-18-701, *et seq.*, the Arkansas Clean Energy Development Act, and portions of the testimony in OG&E's pending rate case Docket No. 10-067-U.

Q. Please summarize OG&E's rationale for a finding that its acquisition of OU Spirit and its WEPAs with Taloga and Keenan are prudent and in the public interest.

A. OG&E maintains that its requested finding is justified by the results of its resource planning analyses. Those results indicate that, as compared to a resource portfolio without this wind energy, it is reasonable to expect that the acquisition of this wind energy will:

- result in lower costs for electricity in the long-term;
- reduce customer exposure to increases in electricity costs in the long-term in the event that natural gas prices and/or carbon dioxide emission compliance costs prove to be higher than expected; and
- result in lower emissions of air pollutants.

[1] In the Matter of Resource Planning Guidelines for Electric Utilities and Consideration of Sec. 111(d)(12) of the Energy Policy Act of 2005.

Q. Please summarize the major conclusions from your review of the Company's analysis and proposals.

A. My review of the Company's proposals is that the acquisition of this wind energy is in the public interest. First, the wind energy is being acquired at a competitive cost. Second, the acquisition of this wind energy appears consistent with the objective of providing service at reasonable rates.

Q. Please summarize your recommendations based upon those conclusions.

A. I recommend that the Commission find that the Company's acquisition of OU Spirit and its WEPAs with Taloga and Keenan are in the public interest.

OG&E Application

Q. Please summarize the resources for which OG&E is requesting a determination in this proceeding.

A. OG&E has requested a finding that its acquisition of the OU Spirit and its purchase of wind energy under the Keenan and Taloga WEPAs are prudent and in the public interest. In the balance of my testimony I refer to the three resources in aggregate as a Combination Wind resource portfolio as well as OUKT.

In this proceeding OG&E is not requesting a finding that the Windspeed line is prudent and in the public interest. It is requesting cost recovery of the Windspeed line in OG&E's pending rate case Docket No. 10-067-U.

Q. What portion of this wind energy and associated costs does OG&E propose to allocate to its Arkansas jurisdictional customers if the Commission approves the acquisitions?

A. OG&E is proposing to allocate this wind energy, and its associated costs, on an energy basis between its Arkansas and Oklahoma jurisdictional customers. Under that approach it would allocate approximately 11% of the wind energy and associated costs to its Arkansas jurisdictional customers.

Q. Please describe the background to OG&E's decision to begin acquiring additional wind energy.

A. OG&E made a decision to begin acquiring additional wind energy as a key component of its strategy to defer the addition of new fossil fuel generation until after 2020. The Company made this strategic decision in late 2007, initially characterizing it as its "2020 Vision". Company witness Motley describes this goal, which OG&E now refers to as its "2020 Goal", in his Direct Testimony in Docket No. 10-067-U, OG&E's current rate case.

OG&E's strategic decision to acquire additional wind resources was based on its estimate of the projected benefits of those resources as a source of energy, not as a source of capacity. OG&E did not decide to acquire wind resources as a source of additional capacity to ensure reliable service because its existing capacity exceeded its projected capacity requirements through 2020. Instead, OG&E decided to acquire additional wind resources as a source of electric energy that would be competitive with new natural gas-fired generation at expected prices for natural gas and carbon and that would result in somewhat lower energy costs if natural gas and carbon prices proved to be higher than expected.

Q. Please describe the major steps OG&E took to begin acquiring additional wind energy.

A. The major steps OG&E took to begin acquiring additional wind energy were to initiate a new transmission line project in order to have sufficient access to new wind resources in general, and to initiate an RFP process to acquire specific wind resources. In May 2008 the Company filed an application with the OCC requesting pre-approval for the Windspeed line, a 345 kV transmission line between Woodward, Oklahoma and Oklahoma City. In parallel, in 2008 OG&E initiated a formal competitive procurement process, with oversight by an Independent Evaluator, to acquire specific wind resources.

Windspeed Line

Q. Please summarize the Company's justification for the Windspeed line.

A. In the Oklahoma case, the Company justified its proposal to build the Windspeed line as part of its strategy to acquire 640 MW of wind resources based on the results of an evaluation of various resource strategies over a 25-year planning horizon under several different future scenarios. Under each scenario it calculated the Net Present Value (NPV) of the projected revenue requirements associated with each resource portfolio. Those projected revenue requirements were based upon projections of a number of inputs including:

- cost of energy from new wind resources. OG&E assumed that it could start acquiring wind energy in 2010 from a set of generic wind farms under 20-year power purchase agreements (PPA) at a levelized busbar cost of $52/MWh. (The busbar is the physical location at which generation is delivered into the transmission system.);
- cost of new transmission to acquire new wind resources. OG&E included a capital cost of $48 million for new transmission to access 640 MW of new wind resources in its economic analyses of alternative resource portfolios; and

- confidential projections of future prices for natural gas and for carbon emissions.

The Company's sensitivity analysis indicated that the NPV of its revenue requirements would be 1 to 2% higher with the 640 MW of wind, as compared to no wind, under scenarios with low gas prices or expected gas prices. The NPV would be 1% to 2% lower with the 640 MW of wind under scenarios with high gas prices and expected or high carbon prices[2].

Company witness Langston[3] summarized the benefits to customers of acquiring additional wind identified through those analyses as follows:

> *Expanding OG&E's commitment from 170 MW to 770 MW of wind is estimated to increase these annual savings to more than 1,653,000 tons of CO2. Based on our forecast of CO2 costs and natural gas prices, the proposed wind projects exclusive of transmission are about a break even to our customers. However, if future natural gas prices and CO2 costs are higher than expected, the addition of wind generation will provide major savings to customers.*

Q. Please describe OG&E's assumptions regarding the timing of the Windspeed line.

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[2] Direct Testimony of Leon Howell (redacted), May 19, 2008, Corporation Commission of Oklahoma Cause No. PUD 200800148, page 5.
[3] Direct Testimony of Jesse B. Langston, May 19, 2008, Corporation Commission of Oklahoma Cause No. PUD 200800148, page 7.

A. In Oklahoma, OG&E requested approval of the Windspeed line in 2008 and proposed to begin building that line immediately upon receipt of its approval. The Company assumed that wind developers would not submit bids into its parallel RFP for wind resources unless they knew adequate transmission would be available if OG&E selected their bid. It further assumed that a delayed in-service date for the Windspeed line would delay its acquisition of wind resources and ultimately lead to higher costs to acquire those resources. OG&E's assumption regarding increasing costs for wind resources was based upon its analyses of the costs for wind energy acquired through an RFP process by Westar Energy in Kansas, its review of trends in construction and turbine costs and its discussions with wind developers and bankers. OG&E was also concerned that Congress might reduce or eliminate the production tax credit which would have the effect of increasing the cost of wind energy.

Q. Please describe OG&E's assumptions regarding the capacity of the Windspeed line and the responsibility for recovery of its costs.

A. OG&E requested approval from the OCC to build Windspeed as a 345 kV transmission line with a thermal capacity rating of 1800 MW and a capital cost of $211 million. OG&E had received approval from the Southwest Power Pool (SPP) to build the line, but as a "Sponsored Upgrade' rather than as a SPP regional line. As a Sponsored Upgrade OG&E, and its customers, would be responsible for all of the cost of the line.

However, the Company only planned to acquire up to 640 MW of wind resources for its native load, and had only assumed a capital cost of $48 million in its economic evaluations of a portfolio with those wind resources and associated new transmission.

OG&E justified its proposal to build a 345 kV line on the grounds that it was the first step in providing much greater access to the extensive wind resource in northwestern Oklahoma. The Company assumed that a number of third parties would eventually contract to transmit wind energy on the line. Based on that assumption OG&E assumed it would be less expensive to build a 345 kV line with a capability of 1800 MW at the outset rather than building a lower voltage line, or making a series of upgrades, with a capability closer to the 640 MW it expected to acquire by 2012.

Q. Did the OCC pre-approve the Windspeed line in 2008?

A. Yes. The OCC approved the Windspeed line in its September 11, 2008 Order in PUD 200800148.

Taloga, Keenan and OU Spirit Wind Resources

Q. Please describe the process through which OG&E made its decisions to enter WEPAs with the Taloga and Keenan wind resources.

A. As described by OG&E witness Langston, in 2008 OG&E initiated a formal competitive procurement process, with oversight by an Independent

Evaluator, to acquire wind energy. In January 2009, through that process, it issued its *2008 Wind Energy RFP* which solicited bids for WEPAs or contracts through which OG&E would own the wind facility when construction was completed. After evaluating the bids it received in response to the RFP, OG&E ultimately selected WEPAs with Taloga and Keenan which it executed in September 2009.

Taloga and Keenan are new wind farms located in Oklahoma. Taloga has a nameplate capability of 130 MW while Keenan has a nameplate capability of 151.8 MW. Keenan is expected to be operating by the end of 2010 while Taloga is now expected to be operating by the second quarter of 2011. OG&E witness Langston provides a detailed description of each facility in his Direct Testimony.

Each WEPA has a term of 20 years. Mr. Langston describes the key pricing and performance provisions of each WEPA in his confidential Direct Testimony. Under each WEPA, Taloga and Keenan must provide a specific minimum output or pay a specified penalty.

The OCC approved OG&E's WEPAs with Keenan and Taloga in Dockets 200900230 and 200900231, respectively.

Q. Did OG&E acquire the OU Spirit facility through the same formal competitive procurement process as it acquired the Taloga and Keenan WEPAs?

A. No. OG&E saw, and pursued, the opportunity to acquire the OU Spirit facility during the first half of 2008. Mr. Langston states that OG&E decided to take advantage of that opportunity at that time based on its assumption that the cost of wind resources was going to increase, and thus if it postponed its decision the cost of acquiring this wind energy would be higher. OG&E was also concerned that Congress might reduce or eliminate the production tax credit.

OU Spirit is a new, 101 MW wind farm located in Oklahoma. It has been operating since December 2009. OG&E witness Langston provides a detailed description of OU Spirit in his Direct Testimony. The OCC approved OG&E's acquisition of OU Spirit in its November 25, 2009 Order in Docket 200900167.

Evaluation of OG&E Proposed Acquisition of Additional Wind Resources

Q. Please describe the standard or test you used to evaluate whether OG&E's proposed acquisitions are in the public interest.

A. I used "reliable service at reasonable rates" as the standard to determine whether these wind energy acquisitions are in the public interest. I chose that standard from a policy perspective because this is the basic obligation that OG&E, like all utilities subject to the Commission's jurisdiction, is required to meet.

Since OG&E is not claiming that it is acquiring these resources in order to ensure reliable service, I have focused solely on "reasonable rates". In order to determine if OG&E's acquisition of OU Spirit and its WEPAs with Keenan and Taloga will enable it to meet the reasonable rate standard, I considered two criteria – reasonable acquisition costs and reasonable long-term energy costs.

Q. What do you mean by reasonable acquisition costs?

A. By reasonable acquisition costs I mean costs that are established through a competitive procurement process, or are consistent with such costs. In other words, has the utility acquired the goods or services in question in a transparent manner and at competitive prices consistent with the terms and conditions of the acquisition? Terms and conditions that can affect prices include the quality of the good or service, delivery / receipt location, and duration of the purchase agreement.

Q. Does OG&E's acquisition of OU Spirit and its WEPAs with Keenan and Taloga meet the reasonable acquisition cost criterion?

A. Yes. The terms and conditions, including pricing, in the WEPAs with Taloga and Keenan were established through a competitive RFP process overseen by an Independent Evaluator. OG&E acquired OU Spirit outside that procurement process, but the levelized cost of wind from OU Spirit is comparable to the levelized cost of wind under the two WEPAs as presented in Mr. Langston's Exhibit JBL-1.

Q. What do you mean by reasonable long-term energy costs?

A. For the type of long-term supply strategy and acquisitions at issue in this proceeding, reasonable long-term energy costs mean costs that are expected to be lower than the costs of alternative strategies under a range of realistic future scenarios. Obviously one must exercise judgment when applying this criterion because of the uncertainty associated with identifying future scenarios, projecting values for the key input assumptions under each scenario, and estimating the probability of each scenario.

Q. Please describe how you evaluated OG&E's acquisition of OU Spirit and its WEPAs with Keenan and Taloga using the reasonable acquisition cost criterion.

A. I evaluated OG&E's acquisition of OU Spirit and its WEPAs with Keenan and Taloga using the reasonable acquisition cost criterion by reviewing the support it provided for each of the three major benefits it attributes to a resource portfolio with this wind energy. Each of those claimed benefits is measured relative to a resource portfolio without this wind energy. Specifically I examined the Company's position that it is reasonable to expect that the acquisition of this wind energy will:

- result in lower costs for electricity in the long-term;

- reduce customer exposure to increases in electricity costs in the event that natural gas prices and/or carbon dioxide emission compliance costs prove to be higher than expected; and
- result in lower emissions of air pollutants.

Q. Please describe the general method OG&E used to estimate the energy cost, hedging and air emission benefits of a resource portfolio with these additional wind resources.

A. OG&E measured the cost, hedging and emission benefits of a resource portfolio with these additional wind resources relative to a base case portfolio without those additional resources. In order to estimate the underlying costs and emissions, OG&E simulated the operation of its system over a 24-year period, 2011 to 2034. OG&E prepared simulations for separate resource portfolios with each individual wind project and also for a resource portfolio with all three wind resources (combined wind resource portfolio). OG&E performed these simulations using a computer model that forecasts the quantity of generation from each resource in each year of the planning horizon, calculates the annual air emissions from that forecast generation and also calculates the annual variable cost of that forecast generation, i.e. electric energy or production costs.

Q. Is that general method an appropriate approach to estimating the benefits of these proposed additional wind resources?

A. Yes.

Estimate of Lower Energy Costs under Combination Wind Resource Portfolio

Q. Please describe the relative quantity of wind energy the Company expects to buy from the three wind resources.

A. The aggregate quality of wind energy the Company expects to buy from the three wind resources represents about five percent of its annual sales.

Q. Please summarize the Company's estimate of the expected net monetary benefits to Arkansas customers of the Combination Wind resource portfolio.

A. Company witness Rowlett indicates that the NPV of cost savings to Arkansas customers from the Combination Wind resource portfolio will be $48.7 million under its "Expected Gas Expected Carbon" scenario (Rowlett Chart 1 page 3). On page 11 of his Direct Testimony, Mr. Rowlett uses this estimate to illustrate the monthly rate and bill impact on residential customers.

In fact, the Company prepared these calculations for eight other future scenarios in addition to its Expected Gas Expected Carbon scenario. Those nine scenarios test combinations of high, expected, and low projections of prices for natural gas and for carbon respectively. Mr. Rowlett presents the NPV of the cost differential under each scenario in Chart 1 of his Direct Testimony. A positive NPV indicates a net savings to

Arkansas customers, i.e., the Combination Wind resource portfolio has lower net costs than the base case, and vice versa.

Q. Please describe the Company's calculation of the net benefits of the Combination Wind resource portfolio under each scenario.

A. The Company calculated the expected net monetary benefit of the Combination Wind resource portfolio to Arkansas customers as the incremental revenue requirements associated with those resources minus the incremental decrease (or increase) in production costs they cause in each scenario. The Company estimated the incremental revenue requirements as the revenue requirements associated with its purchase of OU Spirit plus the cost of purchasing energy under its WEPAs with Taloga and Keenan. The Company calculated the differential in annual production costs between the Combination Wind resource portfolio and the base case portfolio using the results of its simulation modeling. The Company calculated the annual net savings (costs) for each year of its study period and calculated the NPV of that stream of savings (costs).

Mr. Rowlett presents an illustration of that calculation for the "Expected Gas Expected Carbon" scenario in Chart 3 of his Direct Testimony as well as in Exhibit DRR-2.

Q. Do you agree with the Company's estimate of the incremental revenue requirements associated with its Combination Wind resource portfolio?

A. No. The Company has not included any estimate of the incremental transmission costs associated with acquiring those resources, i.e., the costs of the Windspeed line.

The Company states it did not include Windspeed costs in the calculation of net monetary benefits because the OCC had approved the line in 2008 and hence it considered them to be sunk costs (response to APSC 4-9 in Exhibit JRH-9). However, the APSC has not yet ruled on the recovery of Windspeed line costs. Thus, from the perspective of its Arkansas operations, the Windspeed line costs are incremental transmission costs associated with acquiring those wind resources.

Additionally, I would note that while an estimate of incremental annual revenue requirements over time is a necessary assumption input when evaluating whether an acquisition or other resource decision is in the public interest, a more detailed and exacting determination, consistent with the provisions of Arkansas law and the test year and pro forma year which are the subject of OG&E's pending general rate case, should be and is reserved for OG&E's pending case.

Q. Have you prepared estimates of the incremental costs of the Windspeed line associated with the Combination Wind resource portfolio?

A. Yes. I have prepared two estimates of the incremental costs of the Windspeed line associated with the Combination Wind resource portfolio.

One estimate is for a future in which the capability of the line is partially utilized, the other is for a future in which the capability is fully utilized. These estimates are derived in Exhibit JRH – 2.

The partial-utilization estimate assumes that OG&E does not find third parties to buy any transmission service on the Windspeed line in excess of the capability the Company needs to supply its native load. Under this assumption the entire cost of the line is assumed to be borne by the wind energy OG&E acquires for its native load, and the Combination Wind resource portfolio is assumed to bear its share of that amount. The NPV of that assumed incremental cost to Arkansas customers is approximately $22.7 million. The annual amounts underlying that NPV are equal to OG&E's projection of annual wind energy from the combined wind resources multiplied by $15/MWh. That rate, drawn from the OG&E Windspeed proceeding in Oklahoma, is equal to an annual revenue requirement of $33 million, corresponding to a capital cost of $211 million, divided by the projected annual wind energy from 640 MW of new wind resources that OG&E acquires to serve its native load.

The full utilization estimate assumes that OG&E does find third parties to buy all transmission service on the Windspeed line in excess of the capability OG&E requires to supply its native load. Under this assumption the cost of the line is borne pro-rata by all the wind energy transmitted on the line. The NPV of that incremental cost to Arkansas customers is approximately $5.2 million. The annual amounts underlying that NPV are equal to OG&E's projection of annual wind energy from the combined wind resources multiplied by $3.40/MWh. That rate is approximately 23% of the partial-utilization rate, i.e., the ratio of the $48 million capital cost OG&E assumed for the 640 MW of wind resources in its Oklahoma Windspeed proceeding divided by the total capital cost of $211 million.

Q. Have you calculated the impact of including those incremental Windspeed costs on the Company's estimates of monetary benefits to Arkansas customers of the Combination Wind resource portfolio?

A. Yes. I present estimates of the NPV monetary benefits to Arkansas customers of the Combination Wind resource portfolio before and after subtracting incremental Windspeed costs in three charts in Exhibit JRH-3.

The first chart is the Company estimate presented by Mr. Rowlett. The second chart reflects inclusion of Windspeed costs if its capability is partially-utilized. Under those conditions the NPV of the Low Gas Expected Carbon scenario changes from positive to negative, i.e. from a net savings to a net cost. The third chart reflects the inclusion of Windspeed costs if its capability is fully utilized. Under those conditions the NPV of the Low Gas Expected Carbon scenario is reduced but remains positive.

Q. Is your inclusion of incremental Windspeed costs in the evaluation of the Combination Wind resource portfolio meant to be an assessment of the reasonableness of the Windspeed line and its costs?

A. No. The purpose of my analysis is to determine whether the OU Spirit project and the two WEPAs are in the public interest, not to assess the reasonableness of the Windspeed line cost. I have prepared very high level estimates of those costs under two possible situations, partial-utilization and full utilization, to provide a more accurate estimate of the net benefits of the Combination Wind resource portfolio.

The Company has filed for recovery of its Windspeed costs in its general rate case. I am advised by counsel that the general rate case is the appropriate proceeding in which to address the reasonableness of those costs. For the reasons I noted earlier, the detailed review of OG&E's justification for the Windspeed line in the general rate case is necessary, particularly since the capability of the line is so much greater than the capability it needs for its native load.

Q. Does the Expected Gas Expected Carbon scenario represent the most likely estimate of the net monetary benefit to Arkansas customers of the Combination Wind resource portfolio?

A. No. First, there is considerable uncertainty regarding the form and timing of Federal regulation of carbon emissions from existing power plants[4]. It is unlikely a carbon price will be applied to emissions from existing power plants for several years. Second, and of more consequence, there is considerable uncertainty regarding the long-term outlook for natural gas prices. In light of those two facts, it is not clear that the Expected Gas Expected Carbon scenario is the most likely of the nine scenarios, and hence not clear that $48.7 million is the most likely benefit. Instead, the "Low Gas Expected Carbon" scenario is also likely, as is a scenario somewhere between those two.

Q. Please describe the uncertainty regarding the outlook for natural gas prices.

A. The long-term outlook for gas prices has changed dramatically in the past few years primarily due to significant developments in the production of shale gas.

Shale gas is now generally viewed as the long-term marginal source of gas in North America. This means that the cost of producing shale gas is expected to set the market price. Due to the apparent availability of ample quantities of relatively low cost shale gas, and

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[4] In early November 2010 the U.S. Environmental Protection Agency issued guidelines regarding permitting of greenhouse gas emissions from new major stationary sources and from major modifications at existing stationary sources beginning in 2011.

declines in gas use due to the recession, natural gas prices in 2009 and 2010 to date were substantially lower than prices in the prior years. Moreover, as indicated by the annual average of the NYMEX futures prices for Henry Hub[5] plotted on page 1 of Exhibit JRH-4, gas prices are expected to remain below $5.50 through 2013 and possibly longer.

Analysts attribute the likely continuation of relatively low prices in the short-term to factors such as drilling to hold leases by production, production from liquids-rich plays such as the southwestern Marcellus Shale, the need to further delineate the size of plays, and existing high-priced hedges. Thus these current spot prices do not appear to represent the long-term, full replacement cost of shale gas. However, there is considerable uncertainty within the gas industry as to what that long-term replacement cost is and when gas prices will start to reflect it.

The estimates I have reviewed, in addition to the various AEO forecasts, place the long run marginal cost of shale gas between $6/MMBtu and $8/MMBtu[6,7,8,9,10]. The reference case projections in the

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[5] The Henry Hub, located in Louisiana, is a major wholesale market for natural gas. It is one of the most commonly used points for gas price in the U.S. OG&E's projected gas prices were modeled as a Henry Hub price plus a basis to reflect the difference in prices between HH and OG&E's plants.

[6] Hornby, Richard et al. *Avoided Energy Supply Costs in New England: 2009 Report*, Synapse Energy Economics. October 23, 2009.

[7] ___. *Natural Gas Pipeline and Storage Infrastructure Projections through 2030.* ICF International. October 2009.

[8] Dizard, John. *The True Cost of Shale Gas Production.* Financial Times. March 7, 2010.

Energy Information Administration's Annual Energy Outlook (AEO) 2010 fall within that range as indicated in Exhibit JRH-4. That Exhibit also presents the EIA long-term projections of Henry Hub prices from AEO 2008 and AEO 2009.

Q. How do the gas price projections underlying OG&E's Expected Gas and Low Gas scenarios compare to the current outlook for gas prices?

A. The Henry Hub gas price projections underlying OG&E's Expected Gas and Low Gas scenarios are plotted on page 2 of Exhibit JRH-4. The confidential projections of Henry Hub prices underlying the Expected Gas Expected Carbon scenario are [redacted] than the AEO projections, while their projection underlying the Low Gas Expected Carbon scenario are [redacted] the AEO projections. Thus, a scenario with gas prices [redacted] OG&E's Expected Gas and its Low Gas prices could be the most likely.

The confidential projections of Henry Hub natural gas prices underlying the Expected Gas Expected Carbon scenario are in the range of [redacted] from 2014 onward. Over the period 2011 to 2030 those projected annual prices are [redacted], on a levelized basis,

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[9] ____, *2010 Survey of Energy Resources : Focus on Shale Gas*, World Energy Council, September 2010.

[10] ____, *Deutsche Bank Anticipates Strained Global and Domestic Market for Price Inelastic Natural Gas*; Foster Natural Gas Report, September 24, 2010, pages 13 to 16.

than the reference case projections in the Energy Information Administration's Annual Energy Outlook (AEO) 2010. The greatest disparity between the OG&E and AEO forecasts occurs in the near term, between 2014 and 2020.

On the other hand, the confidential projections of Henry Hub natural gas prices underlying the Low Gas Expected Carbon scenario are in the range of [redacted] in the short to medium term. Over the period 2011 to 2030 those projected annual prices are [redacted], on a levelized basis, than the AEO 2010 projections.

Q. Do you agree with the projections of carbon prices underlying its Expected Gas Expected Carbon and Low Gas Expected Carbon scenarios?

A. The long-term projections of carbon prices underlying OG&E's Expected Gas Expected Carbon and Low Gas Expected Carbon scenarios seem generally reasonable except for the assumption they will begin in 2012.

The levels of carbon prices that OG&E has projected under its Expected and High scenarios are lower than, but generally consistent with, those prepared by my colleagues at Synapse in mid-2008[11]. (AEO 2010 does not include projections of carbon prices since Federal

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[11] Schlissel, David et al. *Synapse 2008 CO2 Price Forecasts.* Synapse Energy Economics. July 2008.

regulation of carbon has not yet been approved). The OG&E and Synapse projections are presented in Exhibit JRH-5.

It is not reasonable for OG&E to assume it will begin incurring those carbon prices in 2012. With the failure of Congress to pass a cap-and-trade bill in 2009, it now appears that such a bill will probably not be taken up again for several years. In the absence of such a bill the Environmental Protection Agency may propose regulations for carbon emissions under the Clean Air Act. However, such regulations, even if passed in the near term, would probably not take effect for a few years. Thus, at this point it is reasonable to assume that Federal regulation of carbon, and carbon prices, would not be in effect until approximately 2015 or 2016.

Q. **How would the absence of avoided carbon costs until 2016 affect the NPV of those two Scenarios?**

A. Removing projected savings in carbon costs between 2012 and 2015 reduces the long-term NPV of each Scenario, but not dramatically. The NPV of the Expected Gas Expected Carbon Scenario drops to $45 million while the Low Gas Expected Carbon Scenario drops to $12.5 million. (Those estimates are prior to any reductions for incremental transmission costs). The results of those calculations are presented in Exhibit JRH-6.

Q. Have you calculated the annual and NPV benefits of a scenario midway between Expected Gas and Low Gas, with carbon prices starting in 2016 and incremental Windspeed costs?

A. Yes. Exhibit JRH-7 presents an estimate of the annual and NPV monetary benefits to Arkansas customers of a scenario midway between Expected Gas and Low Gas prices, with carbon prices starting in 2016 and including Windspeed costs assuming full utilization.

That Exhibit begins by comparing the total production costs between the Company's two scenarios assuming no OUKT, i.e., no Combination Wind resources. This comparison demonstrates that under its Low Gas Expected Carbon scenario, OG&E's annual production costs would be reduced by approximately $20 million per year, or 14%. Thus, a Low Gas scenario provides OG&E a window of opportunity to add wind resources while still reducing its total production costs relative to its Expected Gas Expected Carbon scenario.

The Exhibit then demonstrates that the Combination Wind resource portfolio will have a very minimal impact on total production costs, ranging from 0.3% to 1.5% on a NPV basis depending on the scenario. Thus, while the absolute dollars may appear large, they are small relative to the total production costs being paid by OG&E's customers in Arkansas.

Value as a Hedge

Q. What is the basic value to customers of a utility diversifying its supply portfolio?

A. The basic value of diversifying a supply portfolio is to reduce the utility's exposure to future events or market trends that may have a low probability but a high cost to customers. It is somewhat easier to appreciate the quantitative value of diversifying a portfolio if one assigns probabilities to each of the various future possible scenarios and then calculates the overall expected value of the portfolio using those probabilities.

Q. Is it reasonable to expect that OG&E's acquisition of this wind energy will reduce customer exposure to increases in electricity costs due to higher than expected natural gas prices and/or carbon dioxide emission compliance costs?

A. Yes. As noted earlier, OG&E has estimated the NPV benefits of the Combination Wind resource portfolio under nine different scenarios, three of which assume high gas prices and high carbon prices. However OG&E did not provide an estimate of the probability of each of those scenarios.

Exhibit JRH-8, presents my estimate of the expected value of OG&E's portfolio based upon assumed probabilities for each of its nine scenarios. In the chart on page 1 of that Exhibit I assigned probabilities to the possibilities of low (40%), expected (50%) and high (10%) gas prices as well as to zero (10%), expected (70%) and high (20%) carbon prices. With those probabilities I then calculated the probability of each scenario. For example, the low gas expected carbon has a probability of 28%., i.e. Low Gas of 40% times Expected Carbon of 70%. Those scenario probabilities are presented on page 1 of Exhibit JRH-8.

On page 2 of the Exhibit I calculate the overall expected value of the portfolio by multiplying the NPV of each scenario by its probability and adding the values for the nine scenarios. The first chart on page 2 of Exhibit JRH-8 presents the expected value of the Company estimates without any Windspeed costs, a NPV of $42.2 million. The second chart reflects inclusion of Windspeed costs if its capability is partially-utilized, a NPV of $19.5 million. The third chart reflects the inclusion of Windspeed costs if its capability is fully utilized, a NPV of $37 million.

Reduction in air emissions

Q. Is it reasonable to expect that the acquisition of this wind energy will result in lower emissions of air pollutants?

A. Yes. This wind energy will primarily displace generation from natural gas-fired generation. That displacement is expected to lower emissions of carbon dioxide by approximately 4 percent. The wind energy is also expected to displace some coal-fired generation, resulting in somewhat lower emissions of SOx and NOx. These projected reductions are presented in Chart 2 of the Direct Testimony of Company witness Langston.

Conclusions and Recommendations

Q. Please summarize the major conclusions and recommendations from your review of the Company's proposals.

A. The major conclusion from my review of the Company's proposals is that the acquisition of this wind energy is in the public interest. First, the wind energy is being acquired at a competitive cost. Second, the acquisition of this wind energy appears consistent with the objective of providing service at reasonable rates.

I recommend that the Commission find that the Company's acquisition of OU Spirit and its WEPAs with Taloga and Keenan are in the public interest.

Q. Does this complete your Direct Testimony?

A. Yes.

CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing has been served on all parties of record by forwarding the same by postage prepaid first class mail, hand delivery and/or electronic mail on November 19, 2010.

Fran C. Hickman

BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF OKLAHOMA GAS AND ELECTRIC COMPANY FOR AN EXPEDITED ORDER APPROVING A TEMPORARY SURCHARGE TO RECOVER THE COSTS OF A RENEWABLE WIND GENERATION FACILITY, A DECLARATORY RULING THAT CERTAIN RENEWABLE WIND GENERATION PURCHASE POWER AGREEMENTS ARE PRUDENT; AND A DETERMINATION THAT COST OF SUCH PURCHASE POWER AGREEMENTS ARE RECOVERABLE THROUGH THE ENERGY COST RECOVERY RIDER	)	DOCKET NO. 10-073-U

DIRECT EXHIBITS OF
J. RICHARD HORNBY
SYNAPSE ENERGY ECONOMICS, INC.

ON BEHALF OF THE
GENERAL STAFF OF THE
ARKANSAS PUBLIC SERVICE COMMISSION

39

NOVEMBER 19, 2010

PUBLIC VERSION

LIST OF EXHIBITS

James Richard Hornby

PROFESSIONAL EXPERIENCE

Synapse Energy Economics, Inc., Cambridge, MA.
Senior Consultant, 2006 to present.
Provides analysis and expert testimony regarding planning, market structure, ratemaking and supply contracting issues in the electricity and natural gas industries.

Charles River Associates (formerly Tabors Caramanis & Associates), Cambridge, MA.
Principal, 2004-2006, *Senior Consultant*, 1998–2004.
Provided expert testimony and litigation support in energy contract price arbitration proceedings and various utility ratemaking proceedings. Managed a major productivity improvement and planning project for two electric distribution companies in Abu Dhabi. Analyzed a range of market structure and contracting issues in wholesale electricity markets.

Tellus Institute, Boston, MA.
Vice President and Director of Energy Group, 1997–1998.
Presented expert testimony on rates for unbundled retail services in restructured retail markets and analyzed the options for purchasing electricity and gas in those markets.
Manager of Natural Gas Program, 1986–1997.
Prepared testimony and reports on a range of gas industry issues including market structure, unbundled services, ratemaking, strategic planning, market analyses, and supply planning.

Nova Scotia Department of Mines and Energy, Halifax, Canada.

Member, Canada-Nova Scotia Offshore Oil and Gas Board, 1983–1986.
Member of a federal-provincial board responsible for regulating petroleum industry exploration and development activity offshore Nova Scotia.

Assistant Deputy Minister of Energy 1983–1986.
Responsible for analysis and implementation of provincial energy policies and programs, as well as for Energy Division budget and staff. Directed preparation of comprehensive energy plan emphasizing energy efficiency and use of provincial energy resources. Senior technical advisor on provincial team responsible for negotiating and implementing a federal/provincial fiscal, regulatory, and legislative regime to govern offshore oil and gas. Also served as Director of Energy Resources (1982-1983) and Assistant to the Deputy Minister. (1981-1982)

Nova Scotia Research Foundation, Dartmouth, Canada, *Consultant*, 1978–1981.
Canadian Keyes Fibre, Hantsport, Canada, *Project Engineer*, 1975–1977.
Imperial Group Limited, Bristol, England, *Management Consultant*, 1973–1975.

EDUCATION

M.S., Technology and Policy (Energy), Massachusetts Institute of Technology, 1979.
B.Eng., Industrial Engineering (with Distinction), Dalhousie University, Canada, 1973.

TESTIMONY SINCE 2006

Jurisdiction	Company	Docket	Date	Issue
Indiana	Vectren Energy Delivery of Indiana	Cause No. 43839	July 2010	Sales Reconciliation Adjustment
Alaska	Enstar Natural Gas	U-09-069 and U-09-070	March 2010	Rate Design
Pennsylvania	Allegheny Power	M-2009-2123951	March 2010 and October 2009.	Smart meters / advanced metering infrastructure (AMI)
Massachusetts	All Massachusetts regulated electric and gas utilities	D.P.U. 09-125 et al.	December 2009	Avoided Energy Supply Costs in New England
Pennsylvania	Metropolitan Edison Company	M-2009-2123950	October 2009.	Smart meters / AMI
Maryland	Potomac Electric Power	No. 9207	October 2009.	Smart meters / AMI
Maryland	Baltimore Gas and Electric	No. 9208	October 2009 and 2010.	Smart meters / AMI
New Jersey	Jersey Central Power & Light	EO08050326 and EO08080542	July 2009	Demand response programs
Minnesota	CenterPoint Energy	G-008/GR-08-1075	June 2009.	Conservation Enabling Rider
South Carolina	Progress Energy Carolinas	2008-251-E	January 2009.	Compensation for efficiency programs
North Carolina	Progress Energy Carolinas	No. E-2 sub 931	December 2008.	Compensation for efficiency programs

Jurisdiction	Company	Docket	Date	Issue
Maine	Central Maine Power	2007 – 215	October 2008.	Smart meters / AMI
North Carolina	Duke Energy Carolinas	E-7 Sub 831	June 2008	Compensation for efficiency programs (save-a-watt)
Indiana	Duke Energy Indiana	No. 43374	May 2008.	Compensation for efficiency programs (save-a-watt)
Pennsylvania	PECO Energy Company	P-2008-2032333	June 2008.	Residential Real Time Pricing pilot
Arkansas	Entergy Arkansas	06-152-U Phase II A	October 2007	Interim tolling agreement and proposed allocation of Ouachita Power capacity
Washington	Avista Utilities	UE-070804 and UG-070805	September 2007.	Cost allocation, rate design
Arkansas	Entergy Arkansas	06-152-U	January 2007.	Need for load-following capacity
Michigan	Consumers Energy Company	U-14992	December 2006.	Proposed sale of Palisades nuclear plant and associated power purchase
Connecticut	Connecticut Natural Gas Corporation	06-03-04PH01	November 2006.	Gas supply strategy and proposed rate recovery
Michigan	Consumers Energy Company	U-14274-R	October 2006.	Purchases from Midland Cogeneration Venture Limited Partnership
Illinois	WPS Resources and Peoples Energy Corporation	Docket No. 06-0540	October and December 2006.	Service quality metrics and benchmarks
Arizona	Arizona Public Service	E-01345A-05-0816	August 2006 and September 2006.	Hedging strategy and base fuel recovery amount

Jurisdiction	Company	Docket	Date	Issue
Ontario	Transalta Energy Corporation vs Bayer Inc.	Private arbitration	January 2006.	Price for steam under a 20-year contract

Derivation of Rates for Transmission from Windspeed Proceeding in Oklahoma	Total (1)	OG&E evaluation of Windspeed	
Capital Cost (million $)	211	48	23%
Annual Revenue Requirements (million $)	33		
Annual Wind Generation (MWh)	2,130,432		
Transmission Cost Recovery Rate ($/MWH)	15	3.4	23%

1 Responsive Testimony of Scott Norwood, July 11, 2008, Corporation Commission of Oklahoma Cause No.

NPV of Incremental Transmission Costs	NPV (2011 dollars) Tax Adj Wtd Avg Cost of Capital Discount Rate 8.124%	2011	2012	2013	2014	2015	2016	2017	2018
Wind Generation (APSC 2-10)	8.124%	$ 1,081,418	$ 1,192,340	$ 1,317,165	$ 1,461,882	$ 1,588,512	$ 1,716,122	$ 1,842,129	$ 1,963,951
	MWh	1,388,340	1,392,136	1,388,340	1,388,340	1,388,340	1,392,136	1,388,340	1,388,340
Partial Utilization, Transmission @ 15 / MWh	$206,587,956	$ 20,825,100	$ 20,882,040	$ 20,825,100	$ 20,825,100	$ 20,825,100	$ 20,882,040	$ 20,825,100	$ 20,825,100
Arkansas allocation	11.0149%								
	$22,755,457	$ 2,293,864	$ 2,300,136	$ 2,293,864	$ 2,293,864	$ 2,293,864	$ 2,300,136	$ 2,293,864	$ 2,293,864
Full Utilization, Transmission @ 3.4 / MWh	$46,996,312	$ 4,737,464	$ 4,750,417	$ 4,737,464	$ 4,737,464	$ 4,737,464	$ 4,750,417	$ 4,737,464	$ 4,737,464
Arkansas allocation	11.0149%								
	$5,176,597	$ 521,827	$ 523,254	$ 521,827	$ 521,827	$ 521,827	$ 523,254	$ 521,827	$ 521,827

Derivation of Rates for Transmission from Windspeed Proceeding in Oklahoma	Total (1)	OG&E evaluation of Windspeed	
Capital Cost (million $)	211	48	23%
Annual Revenue Requirements (million $)	33		
Annual Wind Generation (MWh)	2,130,432		
Transmission Cost Recovery Rate ($/MWH)	15	3.4	23%

1 Responsive Testimony of Scott Norwood, July 11, 2008, Corporation Commission of Oklahoma Cause No.

NPV of Incremental Transmission Costs	NPV (2011 dollars) Tax Adj Wtd Avg Cost of Capital Discount Rate 8.124%	2019	2020	2021	2022	2023	2024	2025	2026
Wind Generation (APSC 2-10)	8.124%	$ 2,046,061	$ 2,050,071	$ 2,088,295	$ 2,172,390	$ 2,322,406	$ 2,508,207	$ 2,618,282	2838932.009
	MWh	1,388,340	1,392,136	1,388,340	1,388,340	1,388,340	1,392,136	1,388,340	1,388,340
Partial Utilization, Transmission @ 15 / MWh	$206,587,956	$ 20,825,100	$ 20,882,040	$ 20,825,100	$ 20,825,100	$ 20,825,100	$ 20,882,040	$ 20,825,100	$ 20,825,100
Arkansas allocation	11.0149%								
	$22,755,467	$ 2,293,884	$ 2,300,136	$ 2,293,884	$ 2,293,884	$ 2,293,884	$ 2,300,136	$ 2,293,884	$ 2,293,884
Full Utilization, Transmission @ 3.4 / MWh	$46,986,312	$ 4,737,464	$ 4,750,417	$ 4,737,464	$ 4,737,464	$ 4,737,464	$ 4,750,417	$ 4,737,464	$ 4,737,464
Arkansas allocation	11.0149%								
	$5,176,597	$ 521,827	$ 523,254	$ 521,827	$ 521,827	$ 521,827	$ 523,254	$ 521,827	$ 521,827

Derivation of Rates for Transmission from Windspeed Proceeding in Oklahoma	Total (1)	OG&E evaluation of Windspeed	
Capital Cost (million $)	211	48	23%
Annual Revenue Requirements (million $)	33		
Annual Wind Generation (MWh)	2,130,432		
Transmission Cost Recovery Rate ($/MWH)	15	3.4	23%

1 Responsive Testimony of Scott Norwood, July 11, 2008, Corporation Commission of Oklahoma Cause No.

NPV of Incremental Transmission Costs	NPV (2011 dollars) Tax Adj Wtd Avg Cost of Capital Discount Rate 8.124%	2027	2028	2029	2030	2031	2032	2033	2034
Wind Generation (APSC 2-10)	8.124%	3071780.614	3354830.294	3603595.434	3663452.53	4173286.38	4341900.744	4640130.544	
	MWh	1,388,340	1,392,136	1,388,340	1,388,340	370,562	372,043	370,562	370,562
Partial Utilization, Transmission @ 15 / MWh	$206,587,956	$ 20,825,100	$ 20,882,040	$ 20,825,100	$ 20,825,100	$ 5,558,430	$ 5,580,645	$ 5,558,430	$ 5,558,430
Arkansas allocation	11.0149%								
	$22,755,457	$ 2,293,664	$ 2,300,136	$ 2,293,664	$ 2,293,664	$ 612,258	$ 614,702	$ 612,258	$ 612,258
Full Utilization, Transmission @ 3.4 / MWh	$46,996,312	$ 4,737,464	$ 4,750,417	$ 4,737,464	$ 4,737,464	$ 1,264,477	$ 1,269,531	$ 1,264,477	$ 1,264,477
Arkansas allocation	11.0149%								
	$5,176,587	$ 521,827	$ 523,254	$ 521,827	$ 521,827	$ 139,281	$ 139,838	$ 139,281	$ 139,281

Estimates of NPV Benefits of OU Spirit, Taloga and Keenan to Arkansas customers under 9 Scenarios

Chart 1 - OG&E Estimate

Net Present Value ($ Million)		Carbon		
		High	Expected	Zero
Gas	High	$103,137,503	$85,480,273	$69,412,078
	Expected	$68,920,242	$48,667,096	$33,743,650
	Low	$42,532,712	$16,338,889	($2,831,273)

Chart 2 - Partial Utilization, Transmission @ 15 / MWh
Incremental Transmission NPV $ 22,755,457

Net Present Value ($ Million)		Carbon		
		High	Expected	Zero
Gas	High	$80,382,046	$62,724,816	$46,656,621
	Expected	$46,164,785	$25,911,639	$10,988,193
	Low	$19,777,255	($6,416,568)	($25,586,730)

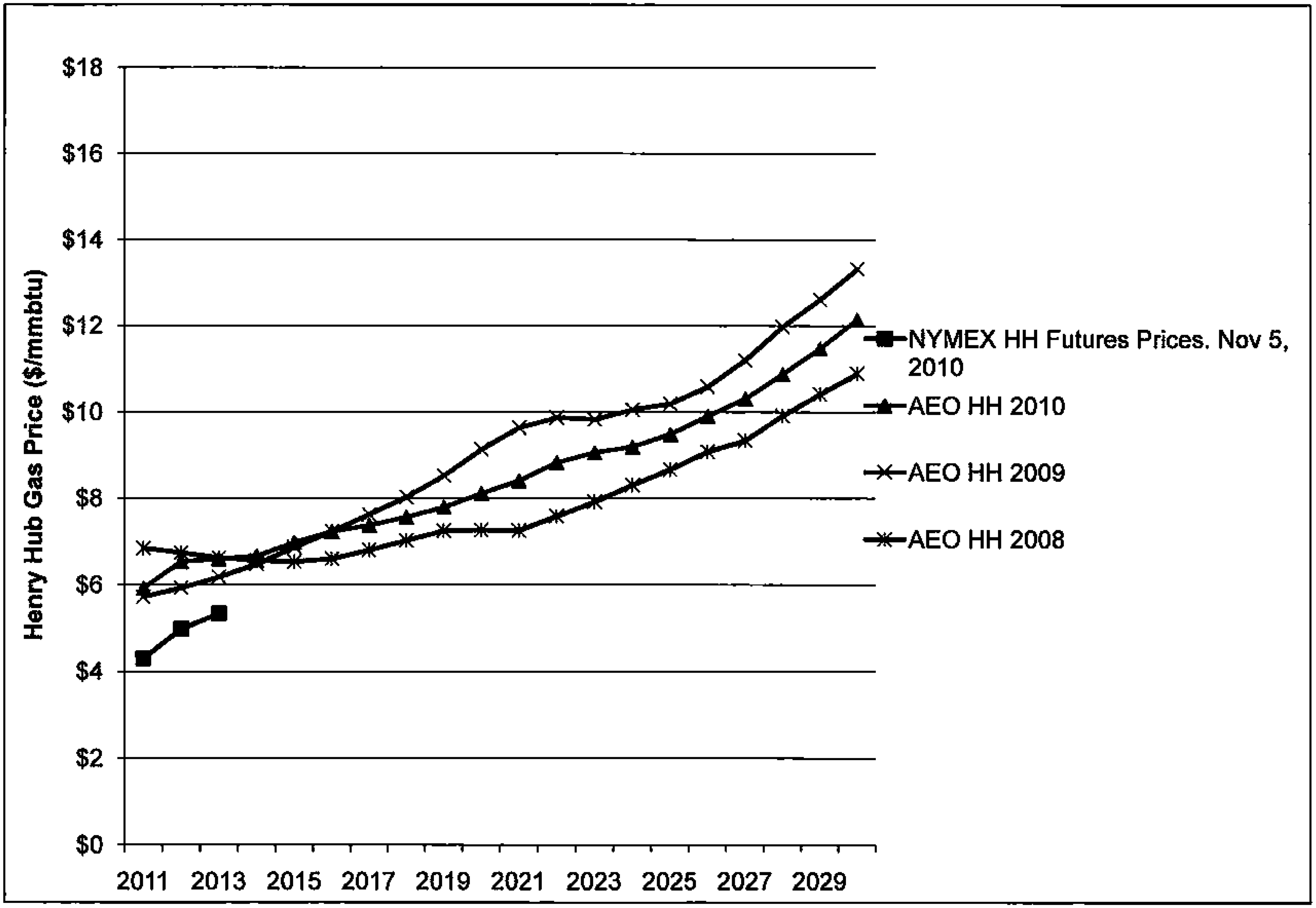
Chart 3 - Full Utilization, Transmission @ 3.4 / MWh
Incremental Transmission NPV $ 5,176,597

Net Present Value ($ Million)		Carbon		
		High	Expected	Zero
Gas	High	$97,960,906	$80,303,676	$64,235,481
	Expected	$63,743,645	$43,490,499	$28,567,053
	Low	$37,356,115	$11,162,292	($8,007,870)

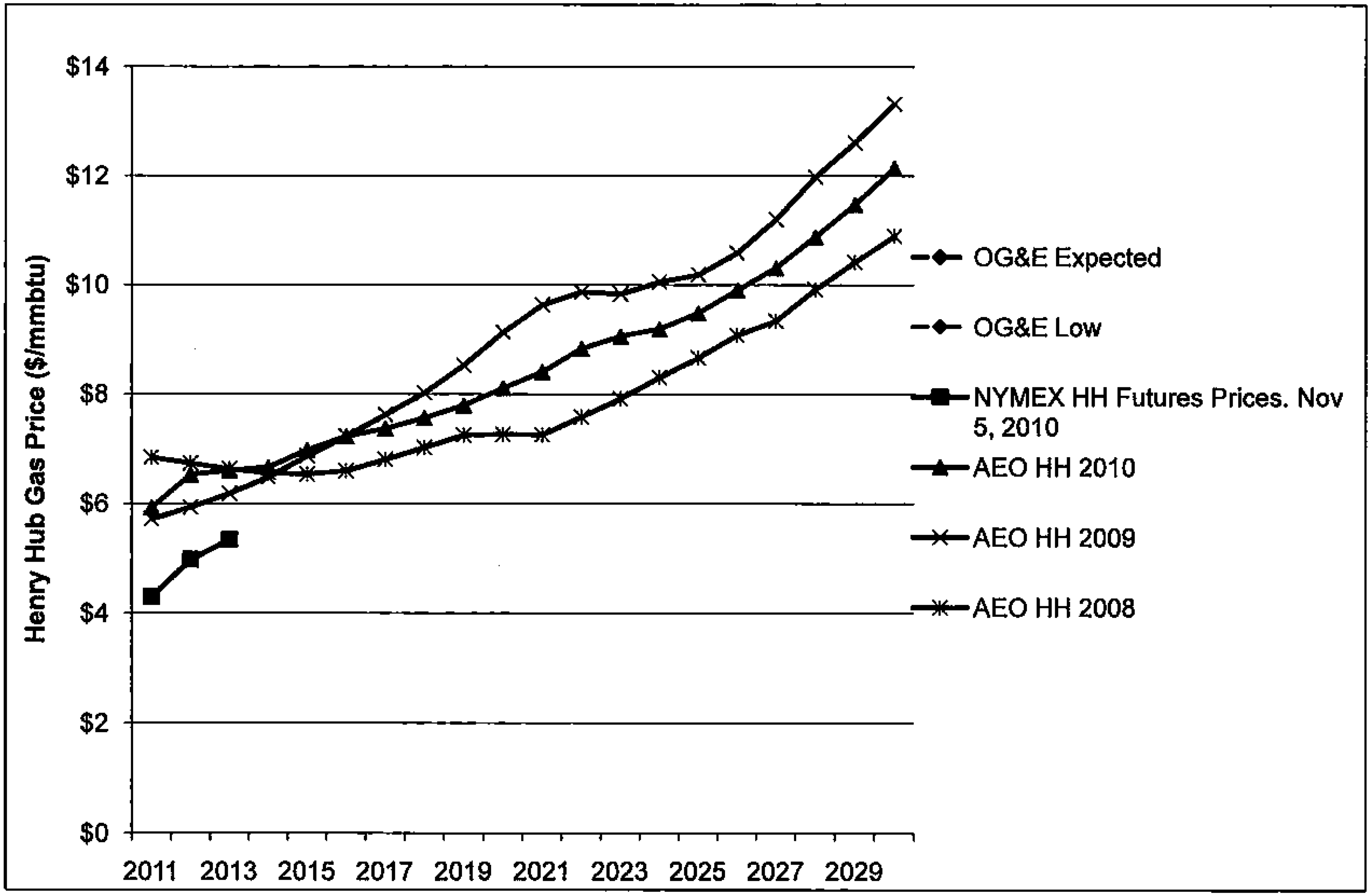
Sources / notes

Chart 1	Direct Testimony of Company witness Rowlett
Chart 2	Chart 1 values less partial utilization transmission costs from Exhibit JRH-2
Chart 3	Chart 1 values less Full utiliation transmission costs from Exhibit JRH-2

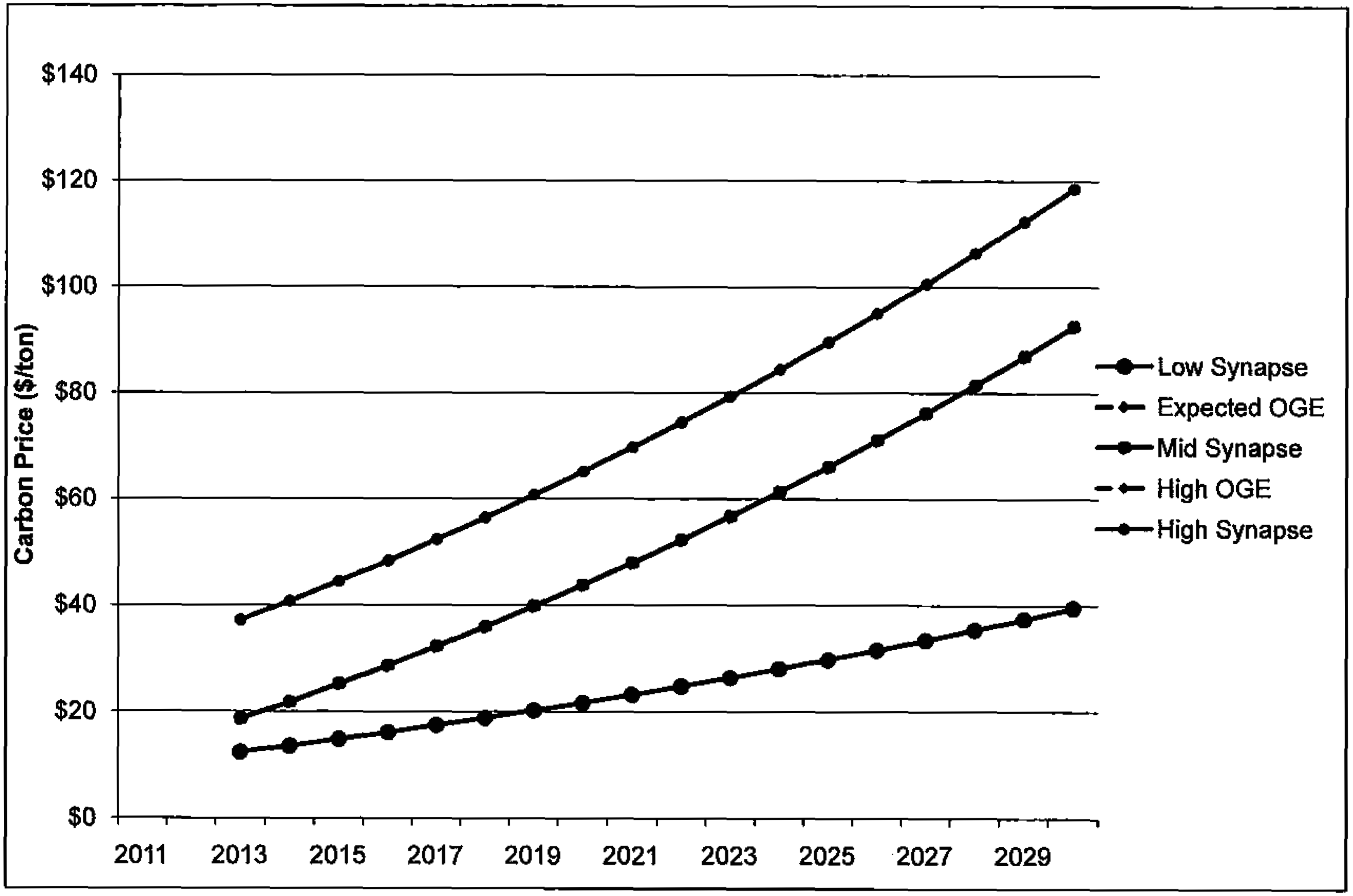
Projections of Henry Hub Gas Prices



Projections of Henry Hub Gas Prices - REDACTED



Projections of Carbon Prices circa 2008 / 2009 - REDACTED



Annual and NPV Benefits for most likely scenarios versus their Total Production Costs

Line			2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
	System Production Cost of CE36 strategy (no OUKT)											
1	Expected Gas Expected Carbon	55%	$1,035,616,714	$1,254,858,100	$1,344,180,507	$1,531,016,090	$1,706,742,599	$1,898,964,455	$2,056,944,080	$2,220,221,140	$2,366,374,379	$2,483,084,021
2	Low Gas Expected Carbon	45%	$850,532,150	$1,082,869,813	$1,194,916,655	$1,318,780,533	$1,483,400,387	$1,591,861,813	$1,718,854,795	$1,844,720,089	$1,965,120,043	$2,048,045,561
3 =55%*1	Scenario midway between Expected Gas & Low Gas	100%	$ 952,320,060	$ 1,177,463,452	$ 1,298,011,803	$ 1,435,510,056	$ 1,587,258,608	$ 1,780,678,178	$ 1,804,825,902	$ 2,051,248,368	$ 2,185,809,900	$ 2,276,595,714
	Arkansas Production Costs CE36 strategy (no OUKT)	11.0149%										
L4 =	Expected Gas Expected Carbon	$	$ 114,072,145	$ 134,221,372	$ 152,466,099	$ 168,639,885	$ 187,995,891	$ 209,169,036	$ 226,574,739	$ 244,555,136	$ 260,653,788	$ 271,306,242
L5 =	Low Gas Expected Carbon	$	$ 93,685,266	$ 119,277,038	$ 131,618,897	$ 145,262,357	$ 161,192,090	$ 175,319,935	$ 189,330,137	$ 203,194,734	$ 216,456,008	$ 225,658,463
L6 =	Scenario midway between Expected Gas & Low Gas	$	$ 104,898,050	$ 129,696,422	$ 143,064,058	$ 158,119,997	$ 175,934,235	$ 193,936,840	$ 209,614,668	$ 225,942,956	$ 240,764,775	$ 250,764,741
L7 = L4 - L5	Impact of Low Gas Prices on Production Cost	$	$ 20,388,880	$ 14,944,334	$ 20,847,202	$ 23,377,528	$ 26,801,800	$ 33,849,101	$ 37,244,603	$ 41,360,404	$ 44,197,758	$ 45,647,779
L8 = L7/L4			18%	14%	14%	14%	14%	16%	16%	17%	17%	17%
	OUKT Net Benefits with Carbon starting 2018, no incremental transmission											
9	Expected Gas Expected Carbon	55%	$ (351,910)	$ (50,867)	$ 465,004	$ 1,305,815	$ 2,320,727	$ 4,747,801	$ 5,635,357	$ 7,990,164	$ 7,760,413	$ 6,971,255
10	Low Gas Expected Carbon	45%	$ (2,467,397)	$ (2,284,832)	$ (1,930,237)	$ (1,429,848)	$ (890,354)	$ 1,661,145	$ 2,053,801	$ 4,051,919	$ 3,879,125	$ 1,873,672
11	Scenario midway between Expected Gas & Low Gas	100%	$ (1,303,679)	$ (1,050,196)	$ (615,554)	$ 107,822	$ 830,739	$ 3,358,806	$ 4,023,657	$ 6,217,954	$ 6,030,333	$ 4,677,343
12	Transmission @ Full Utilization @ 3.4 / MWh		$ (521,827)	$ (523,254)	$ (521,827)	$ (521,827)	$ (521,827)	$ (523,254)	$ (521,827)	$ (521,827)	$ (521,827)	$ (523,254)
	OUKT Net Benefits to Arkansas											
L13 = L9+l12	Expected Gas Expected Carbon	$	$ (873,737)	$ (574,121)	$ (58,823)	$ 844,088	$ 1,798,900	$ 4,224,547	$ 5,113,530	$ 7,468,337	$ 7,268,588	$ 6,448,001
L14 = L10+l12	Low Gas Expected Carbon	$	$ (2,989,224)	$ (2,808,186)	$ (2,458,064)	$ (1,951,675)	$ (1,512,185)	$ 1,137,891	$ 1,531,974	$ 3,530,092	$ 3,357,298	$ 1,350,418
L15 = L11+l12	Scenario midway between Expected Gas & Low Gas	$	$ (1,825,706)	$ (1,578,450)	$ (1,137,381)	$ (414,005)	$ 308,912	$ 2,835,552	$ 3,501,830	$ 5,696,127	$ 5,508,507	$ 4,154,089
	OUKT Net Benefits to Arkansas as % of Production Costs without OUKT											
L16 = L13 / L4	Expected Gas Expected Carbon		-0.8%	-0.4%	0.0%	0.5%	1.0%	2.0%	2.3%	3.1%	2.8%	2.4%
L17 = L13 / L4	Low Gas Expected Carbon		-3.2%	-2.4%	-1.9%	-1.3%	-0.9%	0.6%	0.8%	1.7%	1.6%	0.8%
L18 = L13 / L4	Scenario midway between Expected Gas & Low Gas		-1.7%	-1.2%	-0.8%	-0.3%	0.2%	1.5%	1.7%	2.5%	2.3%	1.7%

Sources
1 *APSC 2-10; Production Cost savings All Projects Exp Gas Exp CO2, OUKT tab, Centennial 56% line 8 and OUKT line 8*
2 *APSC 2-10; Production Cost savings All Projects Low Gas Exp CO2, OUKT tab, Centennial 56% line 8 and OUKT line 8*
9 Exhibit JRH 6 Page 1 of 2
10 Exhibit JRH 6 Page 2 of 2
12 Exhibit JRH 2

Annual and NPV Benefits for most likely scenarios versus their Total Production Costs

Line			2021	2022	2023	2024	2025	2026	2027	2028	2029
	System Production Cost of CE34 strategy (no OUKT)										
1	Expected Gas Expected Carbon	55%	$2,455,818,821	$2,450,582,072	$2,566,640,843	$2,743,244,877	$2,966,387,909	$3,118,857,702	$3,402,338,835	$3,698,862,934	$4,054,902,354
2	Low Gas Expected Carbon	45%	$2,051,328,270	$2,072,021,316	$2,174,618,189	$2,325,710,244	$2,510,123,689	$2,618,157,548	$2,842,436,753	$3,060,323,843	$3,361,323,210
3 =55%*L1	Scenario midway between Expected Gas & Low Gas	100%	$ 2,273,786,873	$ 2,280,228,732	$ 2,390,229,749	$ 2,555,354,347	$ 2,761,074,510	$ 2,894,542,033	$ 3,150,342,953	$ 3,420,520,343	$ 3,742,781,738
	Arkansas Production Costs CE34 strategy (no OUKT)	11.0149%									
L4 =	Expected Gas Expected Carbon	$	$ 270,505,767	$ 269,829,165	$ 282,712,922	$ 302,165,681	$ 320,745,763	$ 343,649,206	$ 374,764,231	$ 407,426,053	$ 446,643,438
L5 =	Low Gas Expected Carbon	$	$ 225,951,758	$ 228,231,076	$ 239,531,799	$ 256,174,658	$ 278,447,614	$ 288,497,585	$ 313,091,566	$ 339,294,581	$ 370,248,390
L6 =	Scenario midway between Expected Gas & Low Gas	$	$ 250,456,463	$ 251,165,025	$ 263,281,417	$ 281,468,728	$ 304,129,590	$ 318,830,878	$ 347,011,532	$ 376,766,885	$ 412,264,787
L7 = L4 - L5	Impact of Low Gas Prices on Production Cost	$	$ 44,554,009	$ 41,598,089	$ 43,181,124	$ 45,991,033	$ 50,254,149	$ 55,151,621	$ 61,672,665	$ 68,131,462	$ 76,387,049
L8 = L7/L4			16%	15%	15%	15%	15%	16%	16%	17%	17%
	OUKT Net Benefits with Carbon starting 2016, no incremental transmission										
9	Expected Gas Expected Carbon	55%	$ 5,322,511	$ 4,818,270	$ 4,663,574	$ 5,338,959	$ 6,866,648	$ 6,418,712	$ 8,287,173	$ 10,905,847	$ 11,248,733
10	Low Gas Expected Carbon	45%	$ 1,516,167	$ 1,639,441	$ 1,845,481	$ 2,750,563	$ 3,726,744	$ 2,855,410	$ 4,150,484	$ 5,949,577	$ 6,468,054
11	Scenario midway between Expected Gas & Low Gas	100%	$ 3,609,650	$ 3,348,347	$ 3,440,432	$ 4,175,781	$ 5,453,601	$ 4,858,126	$ 6,425,654	$ 8,675,561	$ 9,087,427
12	Transmission @ Full Utilization @ 3.4 / MWh		$ (521,827)	$ (521,827)	$ (521,827)	$ (523,254)	$ (521,827)	$ (521,827)	$ (521,827)	$ (523,254)	$ (521,827)
	OUKT Net Benefits to Arkansas										
L13 = L9+L12	Expected Gas Expected Carbon	$	$ 4,800,684	$ 4,297,443	$ 4,141,747	$ 4,813,705	$ 6,344,821	$ 5,894,885	$ 7,765,346	$ 10,382,083	$ 10,726,906
L14 = L10+L12	Low Gas Expected Carbon	$	$ 994,340	$ 1,117,614	$ 1,423,654	$ 2,233,309	$ 3,204,917	$ 2,433,583	$ 3,628,637	$ 5,426,323	$ 5,946,227
L15 = L11+L12	Scenario midway between Expected Gas & Low Gas	$	$ 3,087,829	$ 2,866,520	$ 2,918,605	$ 3,652,527	$ 4,931,864	$ 4,337,299	$ 5,903,827	$ 8,152,327	$ 8,575,601
	OUKT Net Benefits to Arkansas as % of Production Costs without OUKT										
L16 = L13 / L4	Expected Gas Expected Carbon		1.8%	1.6%	1.5%	1.6%	1.9%	1.7%	2.1%	2.5%	2.4%
L17 = L13 / L4	Low Gas Expected Carbon		0.4%	0.5%	0.6%	0.9%	1.2%	0.8%	1.2%	1.6%	1.6%
L18 = L13 / L4	Scenario midway between Expected Gas & Low Gas		1.2%	1.1%	1.1%	1.3%	1.6%	1.4%	1.7%	2.2%	2.1%

Sources

1 APSC 2-10 *Production Cost savings All Projects Exp Gas Exp CO2*, OUKT tab, Centennial 34% line 8 and OUKT 8

2 APSC 2-10 *Production Cost savings All Projects Low Gas Exp CO2*, OUKT tab, Centennial 34% line 8 and OUKT 1

9 Exhibit JRH 6 Page 1 of 2

10 Exhibit JRH 6 Page 2 of 2

12 Exhibit JRH 2

Annual and NPV Benefits for most likely scenarios versus their Total Production Costs

Line			2030	2031	2032	2033	2034	8.124% NPV
	System Production Cost of CE36 strategy (no OUKT)							
1	Expected Gas Expected Carbon	55%	$4,370,630,046	$4,681,720,470	$5,064,511,444	$5,262,135,076	$5,624,602,782	$24,126,748,710
2	Low Gas Expected Carbon	45%	$3,610,014,010	$3,969,153,392	$4,173,290,390	$4,341,900,744	$4,640,130,544	$20,237,077,512
3 =55%*L1	Scenario midway between Expected Gas & Low Gas	100%	$ 4,028,352,829	$ 4,316,064,385	$ 4,663,480,165	$ 4,848,029,626	$ 5,181,590,275	$ 22,376,396,671
	Arkansas Production Costs CE36 strategy (no OUKT)	11.0149%						
L4 =	Expected Gas Expected Carbon	$	$ 481,420,529	$ 515,686,626	$ 557,850,871	$ 579,618,918	$ 619,544,372	$ 2,657,537,244
L5 =	Low Gas Expected Carbon	$	$ 397,639,433	$ 426,183,157	$ 459,683,321	$ 478,256,025	$ 511,105,739	$ 2,229,083,851
L6 =	Scenario midway between Expected Gas & Low Gas	$	$ 443,719,036	$ 475,410,176	$ 513,675,474	$ 534,005,815	$ 570,746,967	$ 2,464,737,717
L7 = L4 - L5	Impact of Low Gas Prices on Production Cost	$	$ 83,781,096	$ 89,503,671	$ 98,167,550	$ 101,362,891	$ 108,438,633	$ 428,443,393
L8 = L7/ L4			17%	17%	18%	17%	18%	16%
	OUKT Net Benefits with Carbon starting 2016, no incremental transmission							
9	Expected Gas Expected Carbon	55%	$ 13,371,900	$ 4,510,019	$ 5,533,616	$ 4,164,540	$ 4,877,484	
10	Low Gas Expected Carbon	45%	$ 8,114,120	$ 2,679,699	$ 3,121,462	$ 3,306,470	$ 3,406,832	
11	Scenario midway between Expected Gas & Low Gas	100%	$ 11,005,899	$ 3,686,375	$ 4,448,147	$ 3,778,409	$ 4,215,681	
12	**Transmission @ Full Utilization @ 3.4 / MWh**		$ (521,827)	$ (139,281)	$ (139,838)	$ (139,281)	$ (139,281)	
	OUKT Net Benefits to Arkansas							
L13 = L9+L12	Expected Gas Expected Carbon	$	$ 12,850,073	$ 4,370,738	$ 5,393,778	$ 4,025,259	$ 4,738,203	$40,069,032
L14 = L10+L12	Low Gas Expected Carbon	$	$ 7,592,293	$ 2,540,418	$ 2,981,624	$ 3,167,189	$ 3,267,551	$7,306,138
L15 = L11+L12	Scenario midway between Expected Gas & Low Gas	$	$ 10,484,072	$ 3,547,094	$ 4,308,309	$ 3,639,128	$ 4,076,410	$25,325,180
	OUKT Net Benefits to Arkansas as % of Production Costs without OUKT							
L16 = L13 / L4	Expected Gas Expected Carbon		2.7%	0.8%	1.0%	0.7%	0.8%	1.5%
L17 = L13 / L4	Low Gas Expected Carbon		1.9%	0.6%	0.6%	0.7%	0.6%	0.3%
L18 = L13 / L4	Scenario midway between Expected Gas & Low Gas		2.4%	0.7%	0.8%	0.7%	0.7%	1.0%

Sources

1 *APSC 2-10: Production Cost savings All Projects Exp Gas Exp CO2, OUKT tab, Centennial 30% line 8 and OUKT 1*
2 *APSC 2-10: Production Cost savings All Projects Low Gas Exp CO2, OUKT tab, Centennial 30% line 8 and OUKT 1*
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12 Exhibit JRH 2

Derivation of assumed probabilities for 9 Scenarios

			Carbon			
			High	Expected	Zero	Total
			20%	70%	10%	100%
Gas	High	10%	2%	7%	1%	
	Expected	50%	10%	35%	5%	
	Low	40%	8%	28%	4%	
	Total	100%				100%

Notes

Probabilities for future Gas Prices and future Carbon Prices per judgment of Mr. Hornby

Probabilities for individual scenarios = Probability of relevant Gas Price * Probability of relevant Carbon Price

Expected NPV Benefits of OU Spirit, Taloga and Keenan to Arkansas customers based on assumed probabilities for 9 Scenarios

Chart 1 - OG&E Estimate

Net Present Value ($ Million)		Carbon			Expected Value
		High	Expected	Zero	
Gas	High	$2,062,750	$5,983,619	$694,121	$42,217,435
	Expected	$6,892,024	$17,033,484	$1,687,183	
	Low	$3,402,617	$4,574,889	($113,251)	

Chart 2 - Partial Utilization, Transmission @ 15 / MWh
Incremental Transmission NPV $ 22,755,457

Net Present Value ($ Million)		Carbon			Expected Value
		High	Expected	Zero	
Gas	High	$1,607,641	$4,390,737	$466,566	$19,461,978
	Expected	$4,616,479	$9,069,074	$549,410	
	Low	$1,582,160	($1,796,639)	($1,023,469)	

Chart 3 - Full Utilization, Transmission @ 3.4 / MWh
Incremental Transmission NPV $ 5,176,597

Net Present Value ($ Million)		Carbon			Expected Value
		High	Expected	Zero	
Gas	High	$1,959,218	$5,621,257	$642,355	$37,040,838
	Expected	$6,374,365	$15,221,675	$1,428,353	
	Low	$2,988,489	$3,125,442	($320,315)	

Sources / notes

Chart 1	Scenario values from Exhibit JRH-3 Chart 1 * scenario probabilities from Exhibit JRH 7, page 1
Chart 2	Scenario values from Exhibit JRH-3 Chart 2 * scenario probabilities from Exhibit JRH 7, page 1
Chart 3	Scenario values from Exhibit JRH-3 Chart 3 * scenario probabilities from Exhibit JRH 7, page 1

OKLAHOMA GAS AND ELECTRIC COMPANY
Response to Arkansas Public Service Commission
Staff Data Request APSC-004
Docket No. 10-073-U

Date Requested: 10/12/2010 Date Required: 10/27/2010 Requested by: Diana Brenske

4-9 **Direct Testimony of Mr. Langston re the "Windspeed" transmission project and Mr. Rowlett re OU Spirit, Keenan and Taloga economic analysis.**

a. **If OG&E needs the "Windspeed" transmission project in order to receive energy from each of the three projects into its system, please explain why it did not include the cost of that transmission project in its economic analysis.**

b. **If OG&E needs the "Windspeed" transmission project in order to receive energy from each of the three projects into its system, please recalculate the NPV's reported in Chart 1 on page 3 to reflect the projected incremental transmission costs of energy from each project. Please provide all supporting workbooks in operational format.**

Response*: a. The"Windspeed" transmission project was developed to allow the areas with favorable wind characteristics additional access to the transmission system. At the time OG&E initially asked the Oklahoma Commission for pre-approval of the Windspeed transmission line the Company had initiated the OG&E Renewable Plan. The following is from the OG&E application in Oklahoma Cause No. PUD 200800148.

Facts.

A. OG&E's portfolio currently includes 170 MW of wind resources: 50 MW from the Sooner Wind facility pursuant to a power purchase agreement with FPL Energy and 120 MW from its Centennial Wind facility.

B. This wind generation provides fuel and environmental benefits to OG&E's customers. The expansion of wind as part of the Company's supply portfolio will help protect customers from higher than expected fuel prices and the risks associated with future environmental mandates.

C. OG&E is initiating the "OG&E Renewable Plan" to significantly expand delivery of the benefits associated with western Oklahoma's vast wind resources to its customers. This initiative seeks to develop up to 600 MW of new wind generation on OG&E's system by 2012. OG&E intends to seek up to 300 MW by 2010 through an RFP for wind energy and the remaining 300 MW by 2012 through a similar RFP

D. Oklahoma's existing transmission infrastructure in western Oklahoma will not support meaningful wind development. Thus, expansion of the transmission system is necessary to take advantage of Oklahoma's vast wind resources.

E. Accordingly, OG&E is proposing the construction of a 345 kV transmission line from Woodward to Oklahoma City. The Company is seeking pre-approval for the construction of this transmission line on or before July 31, 2008 to provide wind developers the assurance necessary to participate in OG&E's forthcoming Request for Proposals ("RFP") for wind energy. The construction of this transmission line is fundamental to obtaining the best value for OG&E's customers.

Windspeed was developed to provide access to wind resources in general which would provide fuel and environmental benefits to OG&E's customers. As specific wind projects were considered to execute the Renewable Plan, Windspeed was considered a sunk cost and was not incremental to the individual project analysis.

b. Windspeed was being developed with or without OU Spirit, Keenan or Taloga and was not considered incremental to the project.

Response provided by: Donald Rowlett
Response provided on: October 27, 2010
Contact & Phone No: Donald Rowlett (405) 553-3604

*By responding to these Data Requests, OG&E is not indicating that the provided information is relevant or material and OG&E is not waiving any objection as to relevance or materiality or confidentiality of the information or documents provided or the admissibility of such information or documents in this or in any other proceeding.

CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing has been served on all parties of record by forwarding the same by postage prepaid first class mail, hand delivery and/or electronic mail on November 19, 2010.

Fran C. Hickman