BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 790

In the Matter of	)	
	)	Direct Testimony of
Application of Duke Energy Carolinas, LLC	)	Judah Rose
for Approval for an Electric Generation	)	for Duke Energy Carolinas
Certificate of Public Convenience and Necessity	)	
to Construct Two 800 MW State of the Art	)	
Coal Units for Cliffside Project	)	

Q. PLEASE STATE YOUR NAME, POSITION, AND BUSINESS ADDRESS.

A. My name is Judah Rose. I am a Managing Director of ICF International ("ICF"). My business address is 9300 Lee Highway, Fairfax, Va. 22031.

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. After receiving a degree in economics from the Massachusetts Institute of Technology (MIT) and a Masters Degree in Public Policy from the John F. Kennedy School of Government at Harvard University, I joined ICF in 1982. I have been working at ICF since then and now direct ICF's wholesale power practice. I have also been a member of the Board of Directors of ICF and I am one of three people in a firm of approximately 1,800 people to have been given the title Distinguished Consultant by the company.

Q. HAVE YOU WORKED WITH PUBLIC SECTOR CLIENTS ON ELECTRIC POWER ISSUES?

A. Yes. ICF has been the principal power consultant to the U.S. Environmental Protection Agency (EPA) continuously for over 25 years, and analyzed all the major policy initiatives involving regional controls on power plant emissions such as SO_2, NO_x, and Hg.

Q. DO YOU HAVE OTHER PUBLIC SECTOR CLIENTS?

A. Yes. ICF has worked with state entities including those in South Carolina, Ohio, New Jersey, California, New York, Connecticut, Kentucky, and Michigan as well as the Federal Energy Regulatory Commission (FERC), U.S. Department of Energy (DOE), Environment Canada, and the European Union.

Q. DO YOU HAVE PRIVATE SECTOR CLIENTS?

A. Yes. ICF provides assistance to electric utilities, financial institutions, power marketers, fuel companies, and independent power producers. ICF also works with Regional Transmission Organizations (RTOs).

Q. PLEASE DESCRIBE YOUR EXPERIENCE?

A. I have extensive experience in assessing the effects of market and regulatory trends on the wholesale power generation sector. This work regularly addresses capacity expansion, Integrated Resource Planning (IRP), market prices for power, and fuel and environmental controls. For example, I regularly run a suite of integrated energy models assessing not only the least-cost options for power supply, but also the effects of power on natural gas markets and the interactions between these markets and environmental controls.

Q. ARE THERE OTHER RELEVANT ASPECTS OF YOUR EXPERIENCE?

A. Yes. I have authored numerous articles in industry journals and spoken at scores of conferences. For additional details, please see my resume which is labeled Exhibit JLR-1.

Q. HAVE YOU TESTIFIED BEFORE OTHER STATE REGULATORS AND LEGISLATORS?

A. Yes. I have testified before state regulators and legislators in Indiana, New Jersey, Ohio, California, Louisiana, New York, Oklahoma, Pennsylvania, Florida, Kentucky, and Minnesota.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of Duke Energy Carolinas'.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to address three issues. The first is to describe recent developments regarding new power plant capital investment costs. The second is to discuss recent developments regarding electricity demand growth and its implications for utility planning. The third is to summarize trends in electric utility Integrated Resource Planning (IRP) generally and relate these trends to the specific results and situation of Duke Energy Carolinas.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. The first section introduces and summarizes my testimony. The second section discusses new power plant capital costs. The third section discusses electricity demand growth and the need for new capacity. The fourth section discusses IRP results from this and other cases.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. The costs of new power plants have escalated very rapidly. This effect appears to be broad based affecting many types of power plants to some degree. One key steel price index has doubled over the last twelve months alone. This reflects global trends as steel is traded internationally and there is international competition among power plant suppliers. Higher steel and other input prices broadly affects power plant capital costs. A key driving force is a very large boom in U.S. demand for coal power plants which in turn has resulted from unexpectedly strong U.S. electricity demand growth and high natural gas prices. Most integrated U.S. utilities have decided to pursue coal power plants as a key component of their capacity expansion plan. In addition, many foreign companies are also expected to add large amounts of new coal power plant capacity. This global boom is straining supply. Since coal power plant equipment suppliers and bidders also supply other types of plants, there is a spill over effect to other types of electric generating plants such as combined cycle plants.

Over the last two years, the growth in U.S. peak electricity demand has been extremely high. Over the last 17 years, long-term average electricity demand growth has been very steady. DSM appears to have played a role in preventing an acceleration in electricity demand growth. Furthermore, in ICF's experience, DSM can be cost effective but has significant lead times. However, claims that electricity demand growth can reliably be stopped should be treated skeptically, especially in the near-term. Furthermore, policies relying on low electricity demand growth can be risky.

The results of Duke's IRP shows that under Base Case assumptions, the All Gas and Nuclear portfolio[1] had the lowest present value of revenue requirements (PVRR)

[1] i.e., 1,734 MW of nuclear, 1,170 MW of combined cycle, and 3,010 MW of peaking combustion turbines, the All Gas and Nuclear portfolio

over the 35 year study period. The Balanced Cliffside portfolio[2] had the second lowest PVRR, but the cost difference between the first and second was very small on a percentage basis, less than one-half of one percent ($232 million out of approximately $49 billion). It is even smaller if the coal capacity is reduced by half as represented in the Balanced Cliffside Shared Ownership portfolio[3]. Additionally, the Balanced Cliffside portfolio performs well under a variety of sensitivities. For example, high gas prices combined with nuclear unavailability causes the Balanced Cliffside portfolio to outperform an All Gas and Nuclear portfolio by 2.3 percent. In such a situation, the portfolio's ability to react positively to a variety of key sensitivities must be considered as a hedge against the risks affecting electric suppliers. Furthermore, an all gas option for all new capacity, a possibility if coal is rejected and nuclear turns out to be problematic, could result in much greater volatility, both for utility rates and overall consumer energy budgets.

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[2] i.e., 1,600 MW of pulverized coal, 1,734 MW of nuclear capacity, and 2,770 MW of combustion turbines, the Balanced Cliffside portfolio

[3] Fifty percent ownership of the new Cliffside units.

Q. WHAT HAVE YOU OBSERVED REGARDING THE CAPITAL COSTS FOR NEW POWER PLANTS?

A. Capital investment costs for new power plants have been increasing significantly. For example:

- **Coal Power Plants** – Actual coal power plant capital costs as reported by coal plants already under construction exceed government estimates of capital costs by a wide margin (i.e., 35 to 40 percent). Additionally, current announced power plants appear to face another increase in costs (i.e., approximately 40 percent additional).
- **Natural Gas Power Plants** – U.S. companies are building very few combined cycles plants, especially relative to the levels of construction between 1999 and 2001. The lack of new construction means that there is limited up-to-date data on the capital costs of constructing a new combined cycle plants. However, the few under construction are likely to cost at least a third more than available cost estimates. Quotations also have greatly risen due to the fact that many of the drivers of recent cost increase would also apply to natural gas power plants (e.g., higher steel price shortages of labor).
- **Wind Turbine Costs** – Wind turbine costs have also risen by as much as one-third to one-half in the areas with viable resource alternatives to fossil generation. Additionally, other renewable resources which typically have higher capital costs are also experiencing large increases in capital cost.
- **Nuclear Power Plant Costs –** No new nuclear plants are under construction in the U.S. and none have received the needed approvals. Thus, information about actual capital costs is based primarily upon vender information, which may

change over time as the new generation of nuclear technologies come closer to commercial development. Although there have been significant improvements in the regulatory framework for the permitting and licensing of new nuclear plants in the U.S., there are still very real concerns about the timing for the construction and commercial operation of the first wave of new nuclear generation.

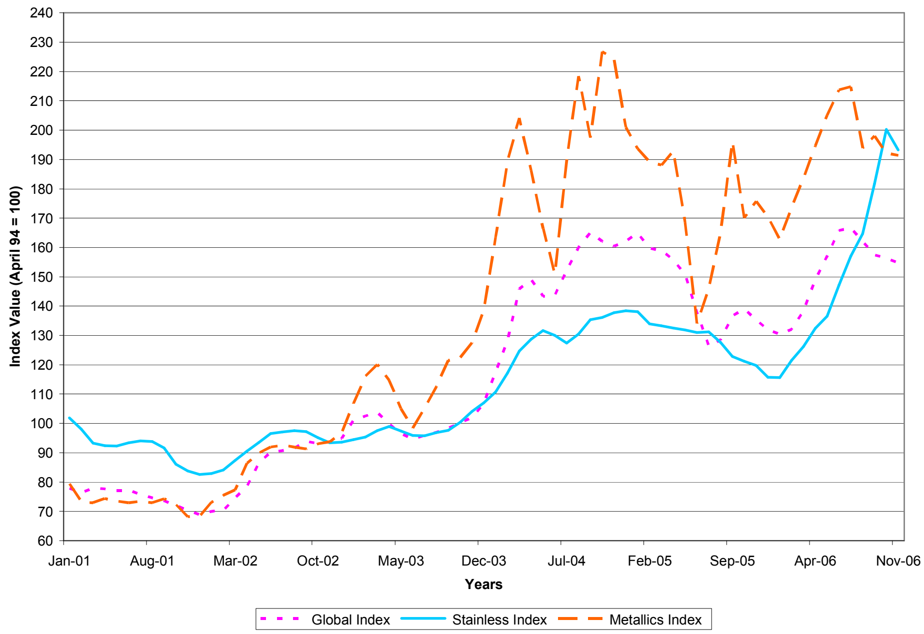
Q. WHY ARE CAPITAL COSTS FOR NEW POWER PLANTS INCREASING?

A. There are two principal reasons why power plant cost increases have greatly exceeded general economy-wide inflation. First, input costs have risen, and second, demand for plants is straining supply.

Q. PLEASE DESCRIBE WHAT YOU MEAN BY TRENDS IN INPUT COSTS.

A. The primary categories of input cost impacting the capital cost of new plant construction are steel costs and labor costs. These costs manifest themselves in various equipment and construction cost categories. Steel costs have increased significantly over the last few years. This increase has occurred globally and reflects international demand for steel from China and other countries. One key steel index doubled over the last twelve months alone (see Exhibit JLR-2). Labor costs, especially for specialists in plant construction also appear to have escalated.

Exhibit JLR-2
Global, Stainless and Metallic's Steel Prices Indices
(Source: www.cruspi.com)



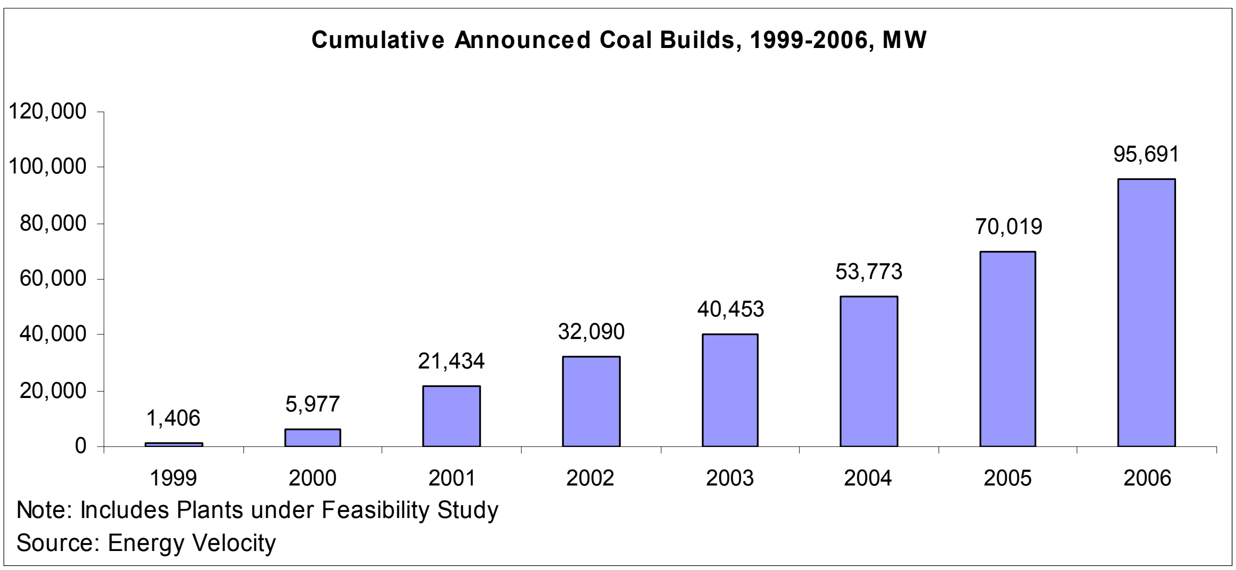
Q. PLEASE DESCRIBE THE INCREASE IN U.S. DEMAND FOR COAL POWER PLANTS.

A. The dramatic increase in demand for new coal power plants is straining the ability of power plant suppliers to meet demand. In 1999, there was only 1,406 MW of new coal power plants planned in the US[4] (see Exhibit JLR-3). Today, the amount of announced coal power plants is 95,691 MW, a nearly 68 fold increase in announced capacity from 1999. Another measure of the size of the current boom is from the US EIA (Energy Information Administration). In 1995, EIA's Annual Energy Outlook (AEO)[5] was forecasting that only new 12,000 MW of unplanned coal plants would be built in the succeeding fifteen years versus 145,000 MW in AEO 2006, a twelve-fold increase. Lastly, actual construction levels are also an indication of the boom in demand. In 2000, there was practically no construction of new coal power plants in the US. This was the

[4] Energy Velocity, Global Energy Online: New Entrants.
[5] EIA's Annual Energy Outlook, 1995

continuation of the pattern of the last twenty years when almost no new coal power plants were built. Today, the amount of coal plants under construction or very recently completed is approximately 11,300 MW[6]. Until recently, the estimates of the costs for building new coal power plants were not based on the actual contracted prices for new coal units, but reflected estimates of the costs from a period of very or extremely depressed demand for new coal power plants. Today, better information is now available on costs.

Exhibit JLR-3



Q. PLEASE DESCRIBE INTERNATIONAL DEMAND FOR NEW COAL PLANTS.

A. There is also a boom in expected coal plant construction internationally. The U.S. EIA expects the amount of worldwide coal-fired generation capacity to jump between 2003 and 2010 by 183,000 MW. This is a large increase in a 7 year period as evidenced by the fact that it is a 16 percent increase in total world coal power plant capacity and that this represents nearly 60 percent of existing U.S. coal power plant capacity which is

[6] Includes the 580 MW Cross Unit 3 which will be on-line on January 1, 2007.

approximately 315,000 MW. This increase appears to be in addition to the U.S. increase which is mostly post-2010 due to the lead time in U.S. coal plant development. Thus, there is a broad-based boom in planned coal power plant construction.

Q. WHAT DOES THE BOOM IN THE DEVELOPMENT OF NEW COAL PLANTS MEAN FOR OTHER ALTERNATIVE FORMS OF GENERATION?

A. The popularity of coal as a resource addition is driven in large part by the fact that new coal generation is very economically attractive, which is a clear indication that alternatives to coal like gas have also undergone significant costs increases as the resources to build all new generation have been taxed. Suppliers are challenged to meet the growing demand for these materials and resources as more utilities announce that they are building generation to keep pace with the growing demand for electricity. Since many suppliers build multiple types of plants, there is a spill over from coal to other types of plants in terms of costs. Engineering, design, construction, and other power plant construction specialists have a fairly high degree of fungibility, and this allows some switching across categories of plants. However, once all these specialists have been utilized incremental demand is expensive to meet.

Q. WAS THIS INCREASE IN DEMAND FOR NEW COAL POWER PLANTS EXPECTED?

A. No, there have been some unexpected developments that have caused this most recent surge in coal power plant demand. These include:

- **Higher U.S. Electricity Demand Growth** – As is discussed more fully below, U.S. peak electricity demand has grown. This recent growth has exceeded industry expectations. Utilities and others are urgently reconsidering their plans for meeting peak loads in the 2010-2013 time period and beyond.

- **Higher Natural Gas Prices** – Between 1994 and 2003, U.S. natural gas prices averaged $2.66/MMBtu[7]. Since 2004, natural gas prices have averaged $6.97/MMBtu (both measured in nominal dollars at the principal market location in Henry Hub Louisiana). This has greatly stimulated interest in new coal power plants, especially following the 2005 peak prices of $15.39/MMBtu[8] which resulted in part from the Katrina and Rita hurricanes. Not only have average gas prices risen, but volatility has more than doubled. The standard deviation of annual Henry Hub natural gas prices a measure of volatility has more than tripled since 1999[9].

Q. WHAT ARE THE IMPLICATIONS OF THE UNEXPECTED INCREASED DEMAND FOR NEW COAL POWER PLANTS?

A. Since the current increase in demand for new coal plants was unexpected, the increase in power plant capital costs could not be fully anticipated. Similarly, the increase in input costs including a recent doubling in specialty steel prices could not be anticipated.

Q. HAVE POWER PLANT COSTS INCREASED IN THE PAST WHEN DEMAND FOR PLANTS INCREASED UNEXPECTEDLY?

A. Yes. As shown in Exhibit JLR-4, the costs of combustion turbines, a key component of new natural gas power plants, increased 60 percent between 1996 and 2002. This increase coincided with the increased demand for new natural gas power plants. It should

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[7] Natural Gas pricing data was determined using Platt's Gas Daily Figures.
[8] Peak price traded on 12/14/2005
[9] In 1999, the standard deviation of annual gas prices between 1991 and 1999 was $0.68/MMBtu. The 1991-2006 number is $2.3/MMBtu.

also be noted that today, almost no new sales are being made and 2005-2006 quotations may not reflect actual market conditions.

EXHIBIT JLR-4
New and Clean CTG Prices Correlate to Overall Wholesale Power Market Conditions (millions of dollars)

Year	New and Clean 7FA	New and Clean 501F (complete set)	New and Clean LM 6000
1996[2]	26	NA	NA
1997[2]	29	32.1	12.1
1998[2]	30	33.7	13.2
1999[2]	33	37.0	13.6
2000[1]	41.0	40.0	14.1
2001[1]	40.5	40.4	14.2
2002[1]	41.5	41.4	14.4
2003[1]	31.3	31.7	10.2
2004[1]	28.5	28.9	10.9
2005[1]	29.2	29.6	11.2
2006[1]	30.9	35.3	12.5

[1] Gas Turbine World (Budgetary / "Asking" Prices) for Simple Cycle GenSets
[2] Personal communication
NA = Not Available

Q. HOW MUCH HAVE CAPITAL COSTS FOR COAL POWER PLANTS INCREASED?

A. While very precise estimates of industry wide cost levels are not fully available[10], the available information supports the following conclusions. First, between 2002-2003 and 2005-2006, the costs of building a new coal fired power plant increased approximately 35 to 40 percent. Second, in 2006, we see that the costs of new coal power plants appear to have further increased another 40 percent. Thus, new coal-fired power plant capital costs have increased approximately 90 to 100 percent since 2002 (1.35 x 1.4 to 1.4 x 1.4).

Q. WHAT IS YOUR BASIS FOR ESTIMATING THAT THE COST OF BUILDING A NEW COAL FIRED POWER PLANT INCREASED APPROXIMATELY 35 TO 40 PERCENT BETWEEN 2002 AND 2005?

[10] Unlike combustion turbines, there is no central source of data.

A. I have compared the cost estimates of the US Energy Information Administration (EIA) in its most recent (i.e., 2006) Annual Energy Outlook (AEO) which I believe to be vestigial to an earlier period before hard data was available and before input prices started rising with recently available cost data from selected coal plants under construction. The EIA estimates that the all-in capital costs for a new coal-fired power plant including financing the construction outlays at $1,397 per kilowatt for a greenfield (i.e., new site; a brownfield is an existing site with an already operating coal power plant), 600 MW size power plant. This cost estimate is expressed by EIA in real 2003 dollars and results in a total cost for a 600 MW plant of $838 million. When this estimate is expressed in 2006 dollars to account for general economy wide inflation of approximately 2.5 percent per year, the resulting estimate is $1,505/kW or $903 million[11].

EIA's estimate has not significantly changed in recent years. Indeed, EIA has not had a chance to update its cost resources to reflect the recent boom in interest in coal plants and the resulting coal power plant cost increases.

The extent to which costs have increased was first revealed when actual power plant data recently became available. This occurred only extremely recently after utilities and Independent Power Producers (IPPs) began to construct new coal power plants. ICF recently reviewed 10 coal-fired power plants currently under construction in the US, and/or recently completed representing approximately 6,000 MW (see Exhibit JLR-5). ICF estimated that the costs of a new Greenfield 600 MW coal fired power plant based on the reported data to be $1,709/kW on a capacity weighted basis before any adjustments to make this estimate comparable to the EIA estimate.

[11] All subsequent estimates in this testimony are expressed in 2006 or today's dollars unless otherwise noted.

EXHIBIT JLR-5
SELECTED U.S. COAL PLANTS UNDER CONSTRUCTION[2]

Coal Plant	Primary Owner	State	Capacity (MW)	Unadjusted Capital Cost ($/kW)
Comanche (CO)	Public Service Co of Colorado	CO	750	2,000
Council Bluffs	MidAmerican Energy Co	IA	790	1,646
Cross 3 & 4	Santee Cooper	SC	1,160	1,319
J K Spruce 2	CPS Energy (City Public Service)	TX	750	1,200
Oak Creek Power Plant	Wisconsin Electric Power Co.	WI	615	1,780
Southwest	Springfield	MO	300	2,323
Weston	Wisconsin Public Service Co.	WI	500	1,886
Wygen II	Black Hills Power Inc	WY	90	1,889
Plum Point	LS Power LLC	AK	665	2,011
Springerville 3[1]	Tri State generation & Transmission Association Inc	AZ	418	2,031
Total/Average			6,038	1,709

[1] Recently completed
[2] ICF has not finished its review of all coal plants under construction.

However, adjustments are needed to be able to compare coal power plant due to the great heterogeneity of coal power plants and U.S. conditions. These adjustments reflect differences between the plants affecting capital costs and differences in the comprehensiveness of the information reported and results in an estimate of all-in capital construction costs. When these adjustments are made, construction to date indicates that a comparable cost estimate to EIA's estimate is $2,066/kW or $1,240 million in 2006$ for a Greenfield 600 MW coal-fired power plant. This 2006 estimate is higher than the unadjusted number because unlike EIA's estimate, the coal plants under construction are larger, more brownfield, and in lower than average cost areas. Thus, apples-to-applies, EIA's estimate is 37 % too low just in terms of plants under construction.

As noted, EIA's estimate is essentially unchanged over the last few years, and the coal power plants identified in Exhibit JLR-5 generally started construction in 2005 and

2006, and hence, signed construction contracts in 2004 – 2006. The fact that even though this information has recently become available, EIA has not yet had a chance to make an adjustment in its estimates to comport with actual data emphasizes the dynamic state of coal power plant capital cost estimation.

Q. WHAT WERE THE TYPES OF ADJUSTMENTS THAT YOU HAD TO MAKE TO COMPARE COAL PLANT COST ESTIMATES?

A. For each estimate of the cost of building a new coal power plant, the following types of adjustments need to be made:

- **Fuel** – Bituminous coal plants cost less all else being equal than sub bituminous coal plants.
- **Design** – While the issues involved in plant design are complex and other testimony addresses these issue, it is useful to note that super critical plants cost more than sub-critical units, plants with full SO_2, NO_x and mercury controls cost more than plants with less extensive controls, and plants with wet cooling costs less than dry cooling.
- **Location** – The costs of construction vary across the country. ICF uses the MEANS index to make adjustments.
- **Size** – There are substantial economies of scale as the capacity of each unit and the number of units built increase.
- **Brownfield versus Greenfield** – Brownfield costs are generally lower than Greenfield costs.
- **Data** – It is not uncommon for reports of cost to exclude certain items notably financing costs and non-site costs such as transmission, etc.

Q. WHAT IS THE BASIS FOR YOUR ASSERTION THAT THE COSTS OF NEW COAL POWER PLANTS APPEAR TO HAVE FURTHER INCREASED BY ANOTHER 40%?

A. The primary basis is the estimates provided to us by Duke. However, I also independently verified this increase using a comparison of ICF's own estimates of coal construction costs with adjustments based on recent reported construction costs.

Q. WHAT EVIDENCE SUPPORTS YOUR CONCLUSION ABOUT COST INCREASES FOR ALL NEW POWER PLANTS?

A. There is anecdotal evidence from others in the industry including those similarly situated to Duke. Additionally, public documents have also begun to provide evidence these rising costs. For example, in the case of the Missouri River Energy Services IRP (addendum filing to the Minnesota PUC on September 7, 2006[12]), the increases in capital costs for Integrated Gasification Combined Cycle (IGCC) coal-fired power plants was 35 percent, for gas-fired combined cycles, 70 percent, gas-fired peakers, 87 percent, and wind turbines, 41 to 71 percent. Costs for coal power plants (non-IGCC) were redacted. Note: gas plant increases were higher on a percentage basis than IGCC. These increases have not been reviewed by ICF in detail and include higher transmission costs and potentially other factors requiring adjustments. However, it does support the view that costs are increasing.

Q. IS THERE ADDITIONAL SIGNIFICANCE TO THE REPORTED INCREASE IN POWER PLANT COSTS GENERALLY?

A. Yes. In addition to supporting the view that the next round of US power plant construction will be more costly than expected, it also means that the competitive

[12] Docket No. ET10/RP-05-1102-Addendum to MRES 2006-2020 Resource Plan.

position of new coal power plants is less harmed than if only coal power plant cost increases were occurring.

Q. WHAT HAS BEEN HAPPENING TO U.S. ELECTRICITY DEMAND GROWTH?

A. U.S. peak electricity demand has grown significantly. In comparison, the North American Electric Reliability Council (NERC) forecast for U.S. peak electricity demand has lagged significantly behind actual demand growth.

Q. WHY IS U.S. ELECTRICITY DEMAND GROWTH RELEVANT TO DUKE ENERGY CAROLINAS?

A. U.S. electricity demand growth is relevant to Duke Energy Carolinas in three principal ways. First, as already noted, rising electricity demand growth, especially unexpected increases in peak demand, increases demand for new power plants generically and can increase their costs as the productive capacity of the industry is strained. Second, Duke is interconnected with other utilities, and in the event that Duke does not expand its capacity (e.g., it takes a wait and see attitude, and demand grows faster than expected), it may have to rely on imports of power from the wholesale power market place. Rising electricity demand creates the potential for higher wholesale power prices than expected. Third, national trends in electricity demand are relevant to the issue of the extent to which demand growth can be controlled via demand side management ("DSM") since the US has been a laboratory for various DSM activities over the last 15 years.

Q. WHAT IS THE STATE OF ELECTRICITY DEMAND GROWTH IN THE US?

A. Exhibit JLR-6 shows US peak electricity demand statistics since 1980. This exhibit also shows the ten year growth rates for peak demand for the last 17 years. These growth rates have averaged 2.5 percent between 1990 and 2006. These long term growth rates together compensate for weather variations since over time weather approaches normal conditions. The trend in electricity demand growth estimated using a regression equation shows that electricity demand growth is slowing only 0.1 percent per year. This is an extremely modest slow down in growth.

Q. IS ELECTRICITY DEMAND IN THE U.S. SLOWING RELATIVE TO U.S. ECONOMIC GROWTH?

A. Only very slightly. Over the same period, 1990 to 2006, the US real GDP ten-year growth has been constant (see Exhibit JLR-7). Thus, there is an almost constant relationship between long-term economic growth and peak electricity demand.

EXHIBIT JLR-6
Average Ten-Year Growth Rates

Year	US Peak Demand (MW)	Average 10-Year Growth Rate
1980	427,058	n/a
1981	428,295	n/a
1982	414,909	n/a
1983	447,526	n/a
1984	451,150	n/a
1985	460,503	n/a
1986	476,993	n/a
1987	496,185	n/a
1988	529,460	n/a
1989	524,110	n/a
1990	546,331	2.49%
1991	551,418	2.56%
1992	548,707	2.83%
1993	575,356	2.54%
1994	585,320	2.64%
1995	620,249	3.02%
1996	616,790	2.60%
1997	637,677	2.54%
1998	660,293	2.23%
1999	681,449	2.66%
2000	678,413	2.19%
2001	687,812	2.23%
2002	714,565	2.68%
2003	709,375	2.12%
2004	704,459	1.87%
2005	758,879	2.04%
2006	798,884	2.62%
	Average	**2.46%**

Source: NERC Electricity Supply and Demand through 2004. 2005 is EIA Annual Energy Outlook. 2006 is ICF estimate.

EXHIBIT JLR-7
GDP Ten-Year Average Growth Rates

Year	GDP in billions of chained 2000 dollars	Average 10-year Growth Rates
1980	5,161.7	n/a
1981	5,291.7	n/a
1982	5,189.3	n/a
1983	5,423.8	n/a
1984	5,813.6	n/a
1985	6,053.7	n/a
1986	6,263.6	n/a
1987	6,475.1	n/a
1988	6,742.7	n/a
1989	6,981.4	n/a
1990	7,112.5	3.26%
1991	7,100.5	2.98%
1992	7,336.6	3.52%
1993	7,532.7	3.34%
1994	7,835.5	3.03%
1995	8,031.7	2.87%
1996	8,328.9	2.89%
1997	8,703.5	3.00%
1998	9,066.9	3.01%
1999	9,470.3	3.10%
2000	9,817.0	3.28%
2001	9,890.7	3.37%
2002	10,048.8	3.20%
2003	10,301.0	3.18%
2004	10,703.5	3.17%
2005	11,048.6	3.24%
2006	11,435.0	3.22%
	Average	**3.16%**

Source: U.S. Bureau of Economic Analysis
Forecast for 2006, U.S. Congressional Budget Office.

Q. OVER THIS PERIOD, HAVE U.S. UTILITY FORECASTS PROPERLY CAPTURED THE STEADINESS OF U.S. DEMAND GROWTH?

A. No. The electric utility industry as a whole under forecasts US peak demand growth with 99.999 percent confidence for multi-year periods. This is documented in a public article in March 2004[13].

Q. HAVE THERE BEEN CONCERNS RAISED ABOUT THE LEVEL OF DEMNAD AND THE NEED FOR NEW GENERATION ADDITIONS TO MEET THIS DEMAND?

A. Yes. Most recently, the North American Electric Reliability Council (NERC), the entity most directly responsible for the reliability of the US power grid under the auspices of the US Federal Energy Regulatory Commission (FERC), recently issued a strong warning that there is a growing discrepancy between growing electricity demand and the lack of supply additions.[14]

> *Available capacity margins, which include only committed resources, are projected to drop below minimum regional target levels in ERCOT, MRO, New England, RFC, and the Rocky Mountain and Canada areas of WECC in the next 2-3 years, with other portions of the Northeastern U.S. Southwest and Western U.S. reaching minimum levels later in the ten year period.(Page 6)….Electric utilities need to commit to add sufficient supply or demand side resources, either through markets, bi-lateral contracts, or self supply to meet minimum regional target levels.*[15]

Q. WHAT IMPLICATIONS DOES THE GROWTH IN DEMAND HAVE UPON DEPLOYMENT OF NEW DEMAND SIDE MANAGEMENT PROGRAMS?

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[13] March 2004, Cloudy Crystal Ball, Public Utilities Fortnightly.

[14] On July 20, 2006, NERC became the Electric Reliability Organization (ERO) for the US. See *2006 Long-Term Reliability Assessment: The Reliability of the Bulk Power Systems in North America*, October 2006.

15 Note that the Reliability *First* Corporation (RFC) and the Midwest Reliability Organization (MRO) cover nearly all the Midwest.

A. In light of the strong evidence of steadily growing U.S. electricity demand throughout most of the history of U.S. DSM programs (i.e., since 1990), electric utilities must plan in a manner that anticipates new growth and ensures that adequate resources are available to keep pace with that growth. In planning to meet the demand for electricity, all alternative measures should be considered including the addition of new supply side resources and the addition of DSM resources. However, the level of demand growth and the resulting stress upon existing resources to meet the demand for electricity suggest that it would be a mistake to believe that a strategy that did not include the development of new generation would be prudent. DSM can play a role in preventing acceleration in peak electricity demand growth. However, DSM cannot be expected to dramatically to slow down electricity demand growth, especially in the near-term, due to implementation lead times to get programs up and running, and the lag between the program initiation and results due to the time it takes to replace the stock of existing equipment with more efficient alternatives under the influence of DSM programs. If a policy is pursued in which potential demand growth is not linked with infrastructure investments, the risks facing utility customers can be substantial as the utility must then rely on stop gap measures such as purchasing from the market or expanded use of peaking units.

Q. CAN YOU SUMMARIZE THE DUKE ENERGY CAROLINAS APPROACH TO IRP ANALYSIS?

A. Yes. First, as described in the testimony of Janice Hager, Vice President of Rates and Regulatory Affairs for Duke Energy Carolinas, a number of portfolios were analyzed using Base assumptions. For each portfolio, the Present Value of Revenue Requirements (PVRR) was calculated. In addition, each portfolio was analyzed over a range of sensitivity scenarios, (e.g., High, Base, and Low natural gas prices, carbon tax, no carbon tax). I would like to focus on two portfolios analyzed in the IRP: (1) the All Gas and Nuclear portfolio which has 1,170 MW of combined cycles, 3010 MW of peaking combustion turbines, and 1,734 MW of nuclear for a total of 5,914 MW, and (2) Balanced Cliffside portfolio which has 1,600 MW of coal, 1,734 MW of nuclear, and 2,770 MW of natural gas for a total of 6,104 MW plus retirements of Cliffside 1-4. These two portfolios performed best under the Base Case assumptions and the various sensitivities analyzed.

Q. IN YOUR EXPERIENCE, IS THIS THE PROPER APPROACH?

A. Yes. There are several alternatives to this approach, none of which are as useful. One alternative would be to only rely on a single Base Case. The problem with this approach is that it fails to address the uncertainties in key variables and their effect on the results. For example, two portfolios might appear similar in the Base Case, but one would out-perform in an alternative case. Another approach would be to calculate a probability distribution for the PVRR of each portfolio based on the scenarios. One disadvantage of this approach is that it is complicated to perform and explain and can inadvertently hide some of the key issues. The scenario approach is common and very useful in that it allows for focused consideration of uncertainty and evaluation of risks by key decision-makers like Commissioners and senior management.

Q. CAN YOU GIVE EXAMPLES OF DIFFICULT ISSUES THAT REQUIRE AN APPROPRIATE ANALYTIC APPROACH TO UNCERTAINTY AND VOLATILITY?

A. Yes. For example, some outcomes may be unattractive because of factors not directly related to PVRR alone, and this may be hidden by overly simple or overly complex approaches. Senior management and Commissioners may not want electric rates to become volatile year-by-year even if PVRR is lower. Also, senior management or Commissioners may want to protect consumers from particular outcomes affecting consumer energy costs for all types of energy which is also not an electric utility PVRR issue only (e.g., avoiding high electricity rates when other, non-electric consumer energy costs are also rising like gasoline and home heating costs).

Q. CAN YOU SUMMARIZE THE RESULTS OF THE DUKE ENERGY CAROLINAS' ANALYSIS?

A. In the Base Case, the All Gas and Nuclear portfolio is the least costly option in terms of PVRR. The Balanced Cliffside portfolio closely followed the more gas intensive option. The difference in the PVRR of the two options in the Base Case is small on a percentage basis at one-half of one percent or $232 million out of approximately $49 billion. It is even smaller if the coal capacity is reduced by half as represented in the Balanced Cliffside Shared Ownership portfolio. Also, under alternative scenarios, the results can change. In the high gas price sensitivity, the Balanced Cliffside portfolio is preferred over the All Gas and Nuclear portfolio. Also, in the event nuclear is unavailable, and natural gas prices are high, the Balanced Cliffside portfolio outperforms the All Gas and

Nuclear portfolio by 2.3 percent. Hence, for a 0.5 percent increase in PVRR, the coal option provides a hedge against a 2.3 percent increase in costs under high gas prices and nuclear unavailability.

Q. WHAT IS YOUR REACTION TO THESE RESULTS?

A. First, nearly all US level ICF studies forecast that the least cost plan is a mix of power plants, mostly coal and gas. While there is regional and scenario variation with respect to the share of coal and gas in the mix, coal and gas together dominate. Also, nuclear and renewables also are forecast to be built, however, the amount constructed is less than coal and gas. Thus, it is unlikely that a no coal option represents the proper balancing of risks. Second, at this point we have more information about fossil-fueled plants in terms of costs and availability than for nuclear power plants. This is important because a key reason the All Gas and Nuclear portfolio is preferred is due in large part to the characterization of the nuclear option as evidenced by the fact that All Gas portfolio (i.e., 2929 MW of combined cycle and 2990 MW of combustion turbine) is not the next best option. Specifically, the capital costs of the nuclear option (before AFUDC – Allowance For Funds Used During Construction) are assumed to be essentially the same as that for the coal plant. As the nuclear option matures in terms of cost estimates and regulatory conditions, the nuclear cost could also increase. To protect against this possibility, a more diverse portfolio makes sense. Third, in many studies that I have performed, relatively small changes in the Base Case parameters result in large difference in the mix of options (e.g., more or less coal as a share of the total), but small differences in the PVRR. This means that the performance of the options across other scenarios and other issues than just PVRR are likely to be very important determinants of the best policy for electric utilities.

Q. WHY IS IT THAT THE VARIOUS OPTIONS ARE BUNCHED TOGETHER IN TERMS OF THE PVRR IN THE BASE CASE?

A. There are three principal reasons. The first is that non-gas power plants cost more to build and less to operate once completed. In the 1990s, all that was built was essentially natural gas plants and modeling showed gas as the dominant option. The recent increases in natural gas and oil prices and the expectations that they will continue to be high cause baseload coal power plants to be more economic than they were in the 1990s as their fuel savings offset their higher initial costs. However, gas and coal remain close under base case conditions. The second is that there is a significant possibility the CO_2 emission controls will be federally mandated sometime in the future. Since coal power plants emit more CO_2 per MWh of electricity produced, and no technology exists in the power industry to control CO_2 emissions from coal power plants, CO_2 programs tend to favor gas. In the view of some observers, the anticipated programs will also be flexible programs in that the cost add-on (i.e., the CO_2 allowance price) adjusts automatically to rebalance the costs of the two options (coal and gas) to be similar so that the less CO_2 intensive option is slightly favored or is at least close to being favored. The third is that US natural gas prices are expected to be set in part based on the level of new coal power plant construction. A gas power plant only world will have higher gas prices making coal more attractive and vice versa. Thus, in the computer-based projection of key parameters, there is a feedback loop between the CO_2 and pro-gas factors on the one hand and the lack of gas supply on the other that keeps the economics of new plant options close and a mix being built.

Q. DOES THIS MEAN THAT IN FACT ALL THE OPTIONS WILL ACTUALLY PERFORM THE SAME?

A. No. Depending on future gas price and environmental regulatory policies in particular, the actual outcomes could be very different. Consider the uncertainties that exist regarding CO_2 emission controls:

- Will they be enacted?
- If so, when?
- How stringent will the controls be overall?
- Will they automatically adjust to changing conditions?
- How will CO_2 emission allowances be provided? Will coal and other power plants on-line in the 2010 - 2013 period be grandfathered and allocated CO_2 emission allowances?
- How will offsets from other countries and other sectors be factored in? How much will they cost?
- Will the US allow China and other countries to keep increasing their CO_2 emissions while they face caps?

As an extreme example, it could be that there would never be a CO_2 control program, and natural gas prices could be high and volatile, and hence, the coal option turns out to be much preferred, especially if the nuclear option is less attractive than expected. Similarly, consider the large uncertainties that exist with respect to natural gas prices (e.g., future world LNG prices, future Alaska gas supply, future world oil prices, future deep off-shore gas supply, etc.). If natural gas prices are very high, consumers are again well served by coal. Thus, while due deference needs to be provided to the results of computer-based projections of trends, there also needs to be appreciation of their limitations.

Q. IF THE BASE CASE PVRR RESULTS ARE SIMILAR WHY NOT JUST RELY EXCLUSIVELY ON GAS OR NUCLEAR WHICH ARE ARGUABLY MORE ENVIRONMENTALLY BENIGN?

A. There are several reasons why such an approach may not be attractive. The first is that reliance on nuclear only for baseload is risky due to cost and other uncertainties such as regulatory problems. The second is that a portfolio of coal, nuclear, and gas or mixed strategy performs better by lowering the variance or range of outcomes or annual rate volatility. Since either coal or natural gas could end up being more attractive, having a mixture is safer than having all one or all the other.

Q. ARE THERE ANALOGIES TO THIS LOWERING OF THE VARIANCE?

A. Yes, there are two useful analogies in this regard. First, even though stocks are generally expected to out-perform bonds with higher average long-term investment returns, the general approach is to have a portfolio containing both stocks and bonds because bonds are less volatile than stocks and they can perform better when stocks perform poorly. Thus, there is a trade-off between risk and return in personal investing which is analogous to having multiple types of plants even if the expected cost is a bit higher to decrease volatility and risk. Second, insurance can also increase expected costs, but lowers the downside impact of unexpected events. Similarly, a modest premium in costs for electrical supply can lower the downside of unexpected outcomes. The scenario approach highlights these trade-offs. However, decision-makers must be aware that these trade-offs cannot be fully modeled in that the amount of risk is a policy decision and ultimately a decision for senior management and regulators.

Q. ARE THERE OTHER REASONS WHY GAS ONLY OR GAS AND NUCLEAR ONLY OPTIONS MAY BE THE WRONG POLICY DECISION, BUT PVRR ANALYSIS DOES NOT FULLY CAPTURE THIS POLICY ISSUE?

A. Yes. First, coal prices are very stable, especially when considering the hedges available via long term coal contracts (See Exhibit JLR-8). The standard deviation of gas prices delivered to U.S. utilities has been nearly equal to that of spot gas prices and 27.4 times higher than for delivered coal prices. This is because spot gas prices are 3.4 to 15 times as variable compared to spot coal prices (see Exhibit JLR-9) and hedging is much more difficult with gas (see Exhibit JLR-10). Second, consumers have limited overall energy options due to the use of oil for transportation, and in many cases, natural gas for home heating. Oil and gas price tend to correlate (see Exhibit JLR-11). Hence, an electric policy overly favorable to natural gas will eliminate a hedge for consumers on overall energy prices. Third, many regions have very positive experiences with coal and nuclear in terms of stable low rates. This experience should be carefully weighed since it may affect consumer expectations about and planning for future conditions. These considerations are highlighted by the scenario analysis which facilitates decision-makers exercise of judgment about the trade-offs between risk and cost.

Exhibit JLR-8
Delivered Utility Fuel Price Volatility Is Much Higher For Gas Than Coal and Delivered Gas Volatility is Close to Gas Spot Prices Volatility – U.S. Average

Year	Nominal$/MMBtu		
	Coal – U.S. Average Delivered Utility Cost[1]	Gas – U.S. Average Delivered Utility Cost[1]	Henry Hub Spot Gas Price[2]
1995	1.32	1.98	1.72
1996	1.29	2.64	2.81
1997	1.27	2.76	2.48
1998	1.25	2.38	2.08
1999	1.22	2.57	2.29
2000	1.20	4.30	4.70
2001	1.23	4.49	3.70
2002	1.26	3.56	3.02
2003	1.28	5.39	5.46
2004	1.36	5.96	5.90
2005	1.54	8.21	8.50
Average	1.29	4.02	3.88
Standard Deviation	0.09	1.90	2.07
Correlation Coefficient with Henry Hub	72%	99%	

[1]Source: EIA Electric Power Annual Table 4.5
[2]Source: Platts' Gas Daily. Prices from 1995 onwards are volume-weighted averages.

Exhibit JLR-9
Delivered Coal Price Volatility Greatly Dampened by Relative Stability in Transportation Costs and Contracting Practices Compared to Spot Coal Prices

Year	Spot Coal Prices[1] (Nominal$/MMBtu)		Average Delivered Coal Costs to Utilities (Nominal$/MMBtu)
	PRB	Central Appalachia 1% Sulfur	U.S.[2]
1995	0.27	0.87	1.32
1996	0.23	1.05	1.29
1997	0.25	1.02	1.27
1998	0.26	1.08	1.25
1999	0.27	1.02	1.22
2000	0.26	0.99	1.20
2001	0.57	1.72	1.23
2002	0.35	1.17	1.26
2003	0.36	1.40	1.28
2004	0.36	2.27	1.36
2005	0.55	2.40	1.54
Standard Deviation	0.12	0.53	0.09
Correlation with Gas Prices	0.64	0.85	0.72

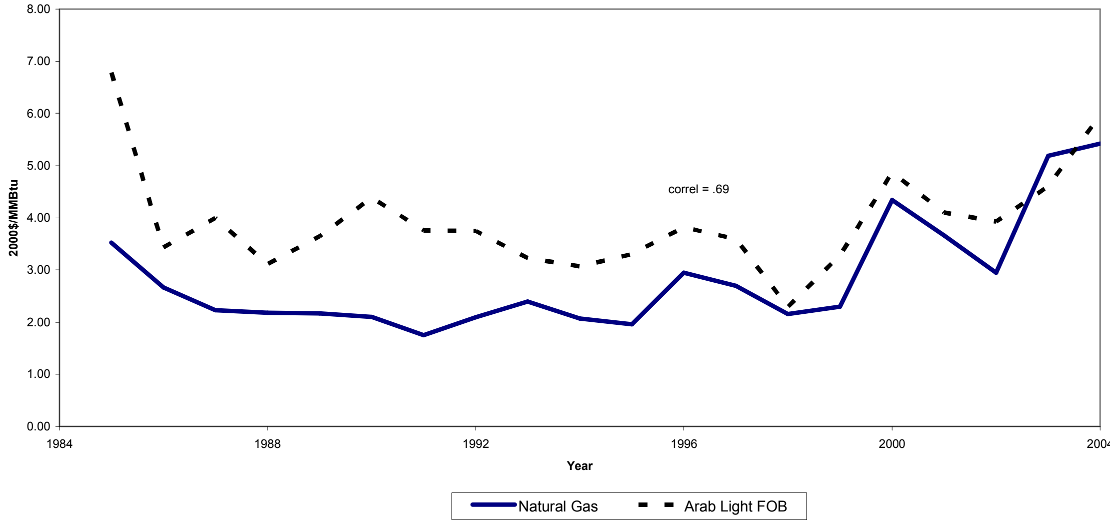
[1] Source: Coal Outlook
[2]Source: EIA AEO 2005

Exhibit JLR-10
Fuel Purchasing and Contracting Favor Coal

Parameter	Coal	Natural Gas
Commodity Contract Type	3 - 5 Year[1]	Spot
Transportation Contract Type	5 – 10 Year	5 – 10 Year
Financial Hedging	No	No

[1]Price fixed for five years on average.

EXHIBIT JLR-11
Crude Oil Prices and Natural Gas Prices are Often Correlated 1970 – 2004, and Hence, the Problem with Gas is Partly an Oil Problem (2000$/MMBtu)



Q. IN CONCLUSION, WHAT IS YOUR REACTION TO A GAS ONLY OR A GAS AND NUCLEAR ONLY STRATEGY?

A. Regulators should give careful consideration to diverse portfolios including coal, gas and nuclear unless they judge that the risks of nuclear are low or that they believe the risks of and volatility associated with heavy reliance on gas is appropriate.

Q. **DOES THIS INCLUDE YOUR TESTIMONY?**

A. Yes

JUDAH L. ROSE

EDUCATION

1982 M.P.P., John F. Kennedy School of Government, **Harvard University**

1979 S.B., Economics, **Massachusetts Institute of Technology**

EXPERIENCE

Judah L. Rose is a Managing Director of ICF International with more than 25 years of experience in the wholesale energy markets. Mr. Rose directs ICF International's wholesale power practice (including assistance to electric utilities, financial institutions, legal firms, Gencos, and IPPs) and co-manages ICF International's fuel market practice. Mr. Rose is one of ICF's Distinguished Consultants, an honorary title given to three of ICF's 1,500 employees, and has served on the Board of Directors of ICF International as the Management Shareholder Representative. Mr. Rose co-manages ICF's IPM© (Integrated Power Model). Mr. Rose has supported the financing of tens of billion dollars of new and existing power plants and is a frequent counselor to the financial community on power issues. He and his colleagues are the authorities the industry turns to for power market analyses and power price forecasts. Mr. Rose also serves many energy industry clients as lead negotiator, and he frequently provides expert testimony and litigation support in power-related court cases. Mr. Rose received a M.P.P. from the John F. Kennedy School of Government, Harvard University, and an S.B. in Economics from the Massachusetts Institute of Technology.

Mr. Rose has publicly testified in state and other legal proceedings, addressed numerous major energy conferences, served as lead negotiator for the Hopi Tribe, authored numerous articles published in Public Utilities Fortnightly, the Electricity Journal, Project Finance International, and written numerous company studies on power, coal, and gas related issues, and managed large consulting projects. Mr. Rose holds a Masters Degree in Public Policy from the John F. Kennedy School of Government at Harvard University and a Bachelor of Science Degree in Economics from the Massachusetts Institute of Technology.

PRESS INTERVIEWS

TV: “The Most With Allison Stewart,” MSNBC, “Blackouts in NY and St. Louis & ongoing
Energy Challenges in the Nation,” July 25, 2006
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Magazine: Business Week
Power Economics
Costco Connection

Newspapers: Denver Post
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LA Times
Arkansas Democratic Gazette
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"Cause No. 42196 - in support of PSI's petition for interim purchased power contract. Filed on 4/26/02."

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"Interim Pricing Report on New York State's Independent System Operator", New York State Public Service Commission (NYSPSC), January 5, 2001

"The need for new capacity in Indiana and the IRP process", Indiana Utility Regulatory Commission, October 26, 2000

"Damage estimates for power curtailment for a Cogen power plant in Nevada", August 2000. CONFIDENTIAL

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“Basic Generation Services and Determining Market Prices.” Testimony to the New Jersey Board of Public Utilities, May 12, 1998.

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“Application of PECO Energy Company for Approval of its Restructuring Plan Under Section 2806 of the Public Utility Code.” Rebuttal Testimony filed July 1997.

“Future Wholesale Electricity Prices, Fuel Markets, Coal Transportation and the Cajun Bankruptcy.” Testimony to Louisiana Public Service Commission, December 1996.

“Curtailment of the Saguaro QF, Power Contracting and Southwest Power Markets.” Testimony on a contract arbitration, Las Vegas, Nevada, June 1996.

“Future Rate Paths and the Cajun Bankruptcy.” Testimony to the U.S. Bankruptcy Court, June 1997.

“Fuel Prices and Coal Transportation.” Testimony to the U.S. Bankruptcy Court, June 1997.

“Demand for Gas Pipeline Capacity in Florida from Electric Utilities.” Testimony to Florida Public Service Commission, May 1993.

"The Case for Fuel Flexibility in the Florida Electric Generation Industry." Testimony to the Florida Department of Environmental Regulation (DER), Hearings on Fuel Diversity and Environmental Protection, December 1992.

SELECTED SPEAKING ENGAGEMENTS

Rose, J.L., AESP, NEEC Conference, Rising Prices and Failing Infrastructure: A Bleak or Optimistic Future, Marlborough, MA, October 23, 2006.

Rose, J.L., Infocast Gas Storage Conference, "Estimating the Growth Potential for Gas-Fired Electric Generation," Houston, TX, March 22, 2006.

Rose, J.L., "Power Market Trends Impacting the Value of Power Assets," Infocast Conference, Powering Up for a New Era of Power Generation M&A, February 23, 2006.

Rose, J.L., "The Challenge Posed by Rising Fuel and Power Costs", Lehman Brothers, November 2, 2005.

Rose, J.L., "Modeling the Vulnerability of the Power Sector", EUCI – Securing the Nation's Energy Infrastructure, September 19, 2005

Rose, J.L., "Fuel Diversity in the Northeast, Energy Bar Association, Northeast Chapter Meeting, New York, NY, June 9, 2005.

Rose, J.L., "2005 Macquarie Utility Sector Conference", Macquarie Utility Sector Conference, Vail, CO, February 28, 2005.

Rose, J.L., "The Outlook for North American Natural Gas and Power Markets", The Institute for Energy Law, Program on Oil and Gas Law, Houston, TX, February 18, 2005.

Rose, J.L. "Assessing the Salability of Merchant Assets – What's on the Horizon?", Infocast – The Market for Power Assets, Phoenix, AZ, February 10, 2005.

Rose, J.L. "Market Based Approaches to Transmission – Longer-Term Role", National Group of Municipal Bond Investors, New York, NY, December 10, 2004.

Rose, J.L. "Supply & Demand Fundamentals – What is Short-Term Outlook and the Long-Term Demand? Platt's Power Marketing Conference, Houston, TX, October 11, 2004.

Rose, J.L. "Assessing the Salability of Merchant Assets – When Will We Hit Bottom?, Infocast's Buying, Selling, and Investing in Energy Assets Conference, Houston, TX, June 24, 2004.

Rose, J. L. "After the Blackout – Questions That Every Regulator Should be Asking," NARUC Webinar Conference, Fairfax, VA, November 6, 2003.

Rose, J. L., “Supply and Demand in U.S. Wholesale Power Markets,” Lehman Brothers Global Credit Conference, New York, NY, November 5, 2003.

Rose, J.L., “Assessing the Salability of Merchant Assets – When Will We Hit Bottom?”, Infocast’s Opportunities in Energy Asset Acquisition, San Francisco, CA, October 9, 2003.

Rose, J.L., “Asset Valuation in Today’s Market”, Infocast’s Project Finance Tutorial, New York, NY, October 8, 2003.

Rose, J.L., “Forensic Evaluation of Problem Projects”, Infocast’s Project Finance Workouts: Dealing With Distressed Energy Projects, September 17, 2003.

Rose, J.L., National Management Emergency Association, Seattle, WA, September 8, 2003.

Rose, J.L., “Assessing the Salability of Merchant Assets – When Will We Hit Bottom?”, Infocast’s Buying, Selling & Investing in Energy Assets, Chicago, IL, July 24, 2003.

Rose, J.L., CSFB Leveraged Finance Independent Power Producers and Utilities Conference, New York, NY, “Spark Spread Outlook”, July 17, 2003.

Rose, J.L., Multi-Housing Laundry Association, Washington, D. C., “Trends in U.S. Energy and Economy”, June 24, 2003.

Rose, J.L., “Power Markets: Prices, SMD, Transmission Access, and Trading”, Bechtel Management Seminar, Frederick, MD, June 10, 2003.

Rose, J.L., Platt’s Global Power Market Conference, New Orleans, LA, “The Outlook for Recovery,” March 31, 2003.

Rose, J.L., “Electricity Transmission and Grid Security”, Energy Security Conference, Crystal City, VA, March 25, 2003.

Rose, J.L., “Assessing the Salability of Merchant Assets – When Will We Hit Bottom?, Infocast’s Buying, Selling & Investing in Energy Assets, New York City, February 27, 2003.

Rose, J.L., Panel Discussion, “Forensic Evaluation of Problem Projects”, Infocast Conference, NY, February 24, 2003.

Rose, J.L., PSEG Off-Site Meeting Panel Discussion, February 6, 2003 (April 13, 2003).

Rose, J.L., “The Merchant Power Market—Where Do We Go From Here?” Center for Business Intelligence’s Financing U.S. Power Projects, November 18-19, 2002.

Rose, J.L., “Assessing U.S. Regional And The Potential for Additional Coal-Fired Generation in Each Region,” Infocast’s Building New Coal-Fired Generation Conference, October 8, 2002.

Rose, J.L., “Predicting the Price of Power for Asset Valuation in the Merchant Power Financings, ”Infocast’s Product Structuring in the Real World Conference, September 25, 2002.

Rose, J.L., “PJM Price Outlook,” Platt’s Annual PJM Regional Conference, September 24, 2002.

Rose, J.L., “Why Investors Are Zeroing in on Upgrading Our Antiquated Power Grid Rather Than Exotic & Complicated Technologies,” New York Venture Group’s Investing in the Power Industry—Targeting The Newest Trends Conference, July 31, 2002.

Rose, J.L., Panel Participant in the Salomon Smith Barney Power and Energy Merchant Conference 2002, May 15, 2002.

Rose, J.L., “Locational Market Price (LMP) Forecasting in Plant Financing Decisions,” Structured Finance Institute, April 8-9, 2002.

Rose, J.L., “PJM Transmission and Generation Forecast”, Financial Times Energy Conference, November 6, 2001.

Rose, J.L., “U.S. Power Sector Trends”, Credit Suisse First Boston’s Power Generation Supply Chain Conference, Web Presented Conference, September 12, 2002.

Rose, J.L., “Dealing with Inter-Regional Power Transmission Issues”, Infocast’s Ohio Power Game Conference, September 6, 2001

Rose, J.L., “Where’s the Next California”, Credit Suisse First Boston’s Global Project Finance Capital Markets Conference, New York NY, June 27 2001

Rose, J.L, “U.S. Energy Issues: What MLA Members Need to Know,” Multi-housing Laundry Association, Boca Raton Florida, June 25, 2001

Rose, J.L., “How the California Meltdown Affects Power Development”, Infocast’s Power Development and Finance Conference 2001, Washington D.C., June 12, 2001

Rose, J.L., “Forecasting 2001 Electricity Prices” presentation and workshop, What to Expect in western Power Markets this Summer 2001 Conference, Denver, Colorado, May 2, 2001

Rose, J.L., "Power Crisis in the West" Generation Panel Presentation, San Diego, California, February 12, 2001

Rose, J.L., " An Analysis of the Causes leading to the Summer Price Spikes of 1999 & 2000" Conference Chair, Infocast Managing Summer Price Volatility, Houston, Texas, January 30, 2001.

Rose, J. L., "An Analysis of the Power Markets, summer 2000" Generation Panel Presentation, Financial Times Power Mart 2000 conference, Houston, Texas, October 18, 2000

Rose, J.L., "An Analysis of the Merchant Power Market, Summer 2000" presentation, Conference Chair, Merchant Power Finance Conference, Atlanta, Georgia, September 11 to 15, 2000

Rose, J.L., "Understanding Capacity Value and Pricing Firmness" presentation, Conference Chair, Merchant Plant Development and Finance Conference, Houston, Texas, March 30, 2000.

Rose, J.L., "Implementing NYPP's Congestion Pricing and Transmission Congestion Contract (TCC)", Infocast Congestion Pricing and Forecasting Conference, Washington D.C., November 19, 1999.

Rose, J.L., "Understanding Generation" Pre-Conference Workshop, Powermart, Houston, Texas, October 26-28, 1999.

Rose, J.L., "Understanding Capacity Value and Pricing Firmness" presentation, Conference Chair Merchant Plant Development and Finance Conference, Houston, Texas, September 29, 1999.

Rose, J.L., "Comparative Market Outlook for Merchant Assets" presentation, Merchant Power Conference, New York, New York, September 24, 1999.

Rose, J.L., "Transmission, Congestion, and Capacity Pricing" presentation, Transmission The Future of Electric Transmission Conference, Washington, DC, September 13, 1999.

Rose, J.L., "Effects of Market Power on Power Prices in Competitive Energy Markets" Keynote Address, The Impact of Market Power in Competitive Energy Markets Conference, Washington, DC, July 14, 1999.

Rose, J.L., "Peak Price Volatility in ECAR and the Midwest, Futures Contracts: Liquidity, Arbitrage Opportunity" presentation at ECAR Power Markets Conference, Columbus, Ohio, June 9, 1999.

Rose, J.L., “Transmission Solutions to Market Power” presentation, Do Companies in the Energy Industry Have Too Much Market Power? Conference, Washington, DC, May 24, 1999.

Rose, J.L., “Repowering Existing Power Plants and Its Impact on Market Prices” presentation, Exploiting the Full Energy Value-Chain Conference, Chicago, Illinois, May 17, 1999.

Rose, J.L., “Transmission and Retail Issues in the Electric Industry” Session Speaker, Gas Mart/Power 99 Conference, Dallas, Texas, May 10, 1999.

Rose, J.L., “Peak Price Volatility in the Rockies and Southwest” presentation at Repowering the Rockies and the Southwest Conference, Denver, Colorado, May 5, 1999.

Rose, J.L., “Understanding Generation” presentation and Program Chairman at Buying & Selling Power Assets: The Great Generation Sell-Off Conference, Houston, Texas, April 20, 1999.

Rose, J.L., “Buying Generation Assets in PJM” presentation at Mid-Atlantic Power Summit, Philadelphia, Pennsylvania, April 12, 1999.

Rose, J.L., “Evaluating Your Generation Options in Situations With Insufficient Transmission,” presentation at Congestion Management conference, Washington, D.C., March 25, 1999.

Rose, J.L., “Will Capacity Prices Drive Future Power Prices?” presentation at Merchant Plant Development conference, Chicago, Illinois, March 23, 1999.

Rose, J.L., “Capacity Value – Pricing Firmness,” presentation at Market Price Forecasting conference, Atlanta, Georgia, February 25, 1999

Rose, J.L., “Developing Reasonable Expectations About Financing New Merchant Plants That Have Less Competitive Advantage Than Current Projects,” presentation at Project Finance International’s Financing Power Projects in the USA conference, New York, New York, February 11, 1999.

Rose, J.L., “Transmission and Capacity Pricing and Constraints,” presentation at Power Fair 99, Houston, Texas, February 4, 1999.

Rose, J.L., “Peak Price Volatility: Comparing ERCOT With Other Regions,” presentation at Megawatt Daily’s Trading Power in ERCOT conference, Houston, Texas, January 13, 1999.

Rose, J.L., “The Outlook for Midwest Power Markets,” presentation to The Institute for Regulatory Policy Studies at Illinois State University, Springfield, Illinois, November 19, 1998.

Rose, J.L., “Developing Pricing Strategies for Generation Assets,” presentation at Wholesale Power in the West conference, Las Vegas, Nevada, November 12, 1998.

Rose, J.L., “Understanding Electricity Generation and Deregulated Wholesale Power Prices,” a full-day pre-conference workshop at Power Mart 98, Houston, Texas, October 26, 1998.

Rose, J.L., “The Impact of Power Generation Upgrades, Merchant Plant Developments, New Transmission Projects and Upgrades on Power Prices,” presentation at Profiting in the New York Power Market conference, New York, NY, October 22, 1998.

Rose, J.L., “Capacity Value – Pricing Firmness,” presentation to Edison Electric Institute Economics Committee, Charlotte, NC, October 8, 1998.

Rose, J.L., “Locational Marginal Pricing and Futures Trading,” presentation at Megawatt Daily’s Electricity Regulation conference, Washington, D.C., October 7, 1998.

Rose, J.L., Chairman’s opening speech and “The Move Toward a Decentralized Approach: How Will Nodal Pricing Impact Power Markets?” at Congestion Pricing and Tariffs conference, Washington, D.C., September 25, 1998.

Rose, J.L., “The Generation Market in MAPP/MAIN: An Overview,” presentation at Megawatt Daily’s MAIN/MAPP – The New Dynamics conference, Minneapolis, Minnesota, September 16, 1998.

Rose, J.L., “Capacity Value – Pricing Firmness,” presentation at Market Price Forecasting conference, Baltimore, Maryland, August 24, 1998.

Rose, J.L., “ICF Kaiser’s Wholesale Power Market Model,” presentation at Market Price Forecasting conference, New York, New York, August 6, 1998.

Rose, J.L., Campbell, R., Kathan, David, “Valuing Assets and Companies in M&A Transactions,” full-day workshop at Utility Mergers & Acquisitions conference, Washington, D.C., July 15, 1998.

Rose, J.L., “Must-Run Nuclear Generation’s Impact on Price Forecasting and Operations,” presentation at The Energy Institute’s conference entitled “Buying and Selling Electricity in the Wholesale Power Market,” Las Vegas, Nevada, June 25, 1998.

Rose, J.L., “The Generation Market in PJM,” presentation at Megawatt Daily’s PJM Power Markets conference, Philadelphia, Pennsylvania, June 17, 1998.

Rose, J.L., “Market Evaluation of Electric Generating Assets in the Northeast,” presentation at McGraw-Hill’s conference: Electric Asset Sales in the Northeast, Boston, Massachusetts, June 15, 1998.

Rose, J.L., “Overview of SERC Power,” opening speech presented at Megawatt Daily’s SERC Power Markets conference, Atlanta, Georgia, May 20, 1998.

Rose, J.L., “Future Price Forecasting,” presentation at The Southeast Energy Buyers Summit, Atlanta, Georgia, May 7, 1998.

Rose, J.L., “Practical Risk Management in the Power Industry,” presentation at Power Fair, Toronto, Canada, April 16, 1998.

Rose, J.L., “The Wholesale Power Market in ERCOT: Transmission Issues,” presentation at Megawatt Daily’s ERCOT Power Markets conference, Houston, Texas, April 1, 1998.

Rose, J.L., “New Generation Projects and Merchant Capacity Coming On-Line,” presentation at Northeast Wholesale Power Market conference, New York, New York, March 18, 1998.

Rose, J.L., “Projecting Market Prices in a Deregulated Electricity Market,” presentation at conference: Market Price Forecasting, San Francisco, California, March 9, 1998.

Rose, J.L., “Handling of Transmission Rights,” presentation at conference: Congestion Pricing & Tariffs, Washington, D.C., January 23, 1998.

Rose, J.L., “Understanding Wholesale Markets and Power Marketing,” presentation at The Power Marketing Association Annual Meeting, Washington, D.C., November 11, 1997.

Rose, J.L., “Determining the Electricity Forward Curve,” presentation at seminar: Pricing, Hedging, Trading, and Risk Management of Electricity Derivatives, New York, New York, October 23, 1997.

Rose, J.L., “Market Price Forecasting In A Deregulated Market,” presentation at conference: Market Price Forecasting, Washington, D.C., October 23, 1997,

Rose, J.L., “Credit Risk Versus Commodity Risk,” presentation at conference: Developing & Financing Merchant Power Plants in the New U.S. Market, New York, New York, September 16, 1997.

SELECTED PUBLICATIONS

Rose, J.L., “Should Environmental Restrictions be Eased to Allow for the Construction of More Power Plants?, The Costco Connection, April 2001.

Rose, J.L., “Deregulation in the US Generation Sector: A Mid-Course Appraisal”, Power Economics, October 2000.

Rose, J. L., “Price Spike Reality: Debunking the Myth of Failed Markets”, *Public Utilities Fortnightly,* November 1, 2000.

Rose, J.L., “Missed Opportunity: What’s Right and Wrong in the FERC Staff Report on the Midwest Price Spikes,” *Public Utilities Fortnightly,* November 15, 1998.

Rose, J.L., “Why the June Price Spike Was Not a Fluke,” *The Electricity Journal*, November 1998.

Rose, J.L., S. Muthiah, and J. Spencer, “Will Wall Street Rescue the Competitive Wholesale Power Market?” *Project Finance International*, May 1998.

Rose, J.L., “Last Summer’s “Pure” Capacity Prices – A Harbinger of Things to Come,” *Public Utilities Fortnightly,* December 1, 1997.

Rose, J.L., D. Kathan, and J. Spencer “Electricity Deregulation in the New England States,” *Energy Buyer*, Volume 1, Issue 10, June-July 1997.

Rose, J.L., S. Muthiah, and M. Fusco, “Financial Engineering in the Power Sector,” *The Electricity Journal,* Jan/Feb 1997.

Rose, J.L, S. Muthiah, and M. Fusco, “Is Competition Lacking in Generation? (And Why it Should Not Matter),” *Public Utilities Fortnightly,* January 1, 1997.

Mann, C. and J.L. Rose, “Price Risk Management: Electric Power vs. Natural Gas,” *Public Utilities Fortnightly,* February 1996.

Rose, J.L. and C. Mann, “Unbundling the Electric Capacity Price in a Deregulated Commodity Market,” *Public Utilities Fortnightly,* December 1995.

Booth, William and J.L. Rose, "FERC's Hourly System Lambda Data as Interim Bulk Power Price Information," *Public Utilities Fortnightly,* May 1, 1995.

Rose, J.L. and M. Frevert, "Natural Gas: The Power Generation Fuel for the 1990s." Published by Enron.

EMPLOYMENT HISTORY

ICF Resources Incorporated	Managing Director	1999-Present
	Vice President	1996-1999
	Project Manager	1993-1996
	Senior Associate	1986-1993
	Associate	1982-1986