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August 31, 2011

Chairman Todd A. Snitchler
Public Utilities Commission of Ohio
Ohio Power Siting Board
180 East Broad Street
Columbus, Ohio 43215-3793

Matthew J. Satterwhite
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RE:

In the Matter of the Commission Review	)	
of the Capacity Charges of	)	Case No. 10-2929-EL-UNC
Columbus Southern Power Company	)	
and Ohio Power Company	)	

Dear Chairman Snitchler:

Attached please find the testimony of Columbus Southern Power Company and Ohio Power Company (AEP Ohio) witnesses in the above listed docket required to be filed today in the procedural schedule issued in the August 11, 2011 Entry. Those witnesses providing pre-filed direct testimony are:

Richard E. Munczinski
William A. Klun
Frank C. Graves
Dana E. Horton
Kelly D. Pearce

Please contact me if there are any questions.

Cordially,

Matthew J. Satterwhite
Senior Counsel

Testimony attached

CERTIFICATE OF SERVICE

I hereby certify that this letter and the testimony accompanying it was served by electronically pursuant to the August 11, 2011 Entry in this case, upon counsel for the entities below on this August 31, 2011.

Matthew J. Satterwhite

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EXHIBIT NO. ______

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Commission Review of the Capacity Charges of Ohio Power Company and Columbus Southern Power Company	))))	Case No. 10-2929 -EL-UNC

DIRECT TESTIMONY OF
FRANK C. GRAVES
ON BEHALF OF
COLUMBUS SOUTHERN POWER COMPANY
AND
OHIO POWER COMPANY

Filed: August 31, 2011

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO
DIRECT TESTIMONY OF
FRANK C. GRAVES
ON BEHALF OF
COLUMBUS SOUTHERN POWER COMPANY
AND
OHIO POWER COMPANY

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

A. My name is Frank C. Graves. I am a Principal at *The Brattle Group*, where I am also co-leader of the Utility Practice Area. My firm is located at 44 Brattle Street, Cambridge, MA, 02138.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I will explain why it is appropriate for Columbus Southern Power Company (CSP) and Ohio Power Company (OPCo) (also referred to as "AEP Ohio") to charge Competitive Retail Electric Service (CRES) providers within its franchise service territories an amount for capacity that reflects the embedded (fully allocated accounting) cost of the assets AEP Ohio must hold under its Fixed Resource Requirements (FRR) obligations as a member of PJM, rather than the capacity price set in PJM's Reliability Pricing Model (RPM) auctions.

Q. ARE YOU REVIEWING OR ASSESSING THE SPECIFIC PARAMETERS OF AEP OHIO'S EMBEDDED COST CALCULATIONS AND THEIR FAITHFULNESS TO THE TRUE COST OF SERVICE?

A. No. I am not commenting on the accuracy of AEP Ohio's calculations or formulas for specifying the embedded capacity cost. Rather, I am commenting on the policy question of whether (assuming such calculations are accurate) the AEP Ohio proposal is just and reasonable, especially in light of whether it could have an undue, adverse impact on retail power marketing or wholesale generation competition.

Q. WHAT IS YOUR EDUCATIONAL BACKGROUND AND RELEVANT EXPERTISE?

A. I have an M.S. in Management from the MIT Sloan School of Management with a concentration in finance, and a B.A. in Mathematics from Indiana University. I have been consulting to the electric industry for over 30 years on matters related to long term resource planning, pricing, prudence, risk management, fuel and power procurement, environmental compliance, market forecasting and performance, regulatory policy impacts, and other long term influences on utility assets, costs, and obligations.

I have appeared numerous times as an expert witness before state and federal courts and regulatory bodies, including the Federal Energy Regulatory Commission (FERC), and utility commissions (or administrative law judges for them) in Ohio, Illinois, Pennsylvania, Wisconsin, Kentucky, Michigan, Massachusetts, Vermont, New York, Virginia, Texas, California, New Mexico, and Utah to explain tradeoffs and likely costs and benefits of utility activities and decisions. I have also been a witness in state and federal courts regarding contract disputes between energy companies.

In regard to the topics at issue in this proceeding, I have been very active in consulting on the design of terms and conditions, supply procurement mechanisms, and pricing and valuation of Default, or Standard Service Offer, in states with retail access, as well as in how those service designs interact with market performance and the viability of the incumbent utility and retail electric providers. A detailed description of my expertise is attached as Appendix A to this testimony.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS AND OPINIONS.

A. The unique circumstances in PJM of AEP Ohio as an FRR entity obligated to supply all the capacity needs of any/all load in its franchise territory make it inappropriate to use a PJM RPM-based price as the tariffed rate for transferring AEP Ohio's capacity to CRES providers. The current RPM price is much lower than AEP Ohio's embedded costs, so it would not be compensatory for AEP Ohio. This difference will increase in the next two years, as RPM prices for 2012/2013 and 2013/2014 are even lower. RPM prices are short term (one-year) rates that do not reflect the costs of serving the long term, more binding and broader reliability obligations that AEP Ohio faces (as an FRR utility) but that a CRES provider does not.

In addition to current RPM prices being below AEP Ohio's embedded cost, PJM market energy prices also are low right now, largely due to the recession and the emergence of inexpensive shale gas. This combination of low capacity and energy prices is making CRES providers more active than in the recent past, making it essential that the price they face for capacity from AEP Ohio be fair and compensatory. Using an RPM-based price would introduce uneconomic bypass opportunities for the CRES providers, at the expense of AEP Ohio customers and shareholders. While such bypass would undoubtedly increase the prevalence of retail providers in AEP Ohio's service territory, it would not be fostering efficient competition.

CONTEXT FOR THE DISPUTE

Q. PLEASE PROVIDE A BRIEF SUMMARY OF YOUR UNDERSTANDING OF THE BACKGROUND FOR THIS DISPUTE.

A. The disputed issue in this case which I am addressing is whether AEP Ohio's charge for releasing capacity to CRES providers that provide retail electric supply services in AEP Ohio's territories should be based on AEP Ohio's own costs of service for the underlying generation assets it is required to hold as an FRR provider, or should be based on the one-year market value of capacity as it has arisen in PJM's Reliability Pricing Model (RPM) for three-year forward planning reserve obligations. AEP has proposed the former, embedded cost basis (with formula rates) while commenters (and the interim policy of the PUCO) tend to prefer the PJM RPM auction price basis.

The cost difference between the two viewpoints is material. For the PJM Planning Year beginning June 1, 2011, the RPM auction price of capacity in the AEP region (unconstrained PJM) is \$116.16/MW-day, but when this is scaled up for PJM reserve margins and capacity loss factors, it is \$145.79 in AEP Ohio's service territories. In contrast, the correspondingly adjusted embedded cost of service for AEP Ohio's generation plant is \$355.72/MW-day. If this is reduced for the recent past energy operating margins that would have been available to

AEP Ohio in PJM's wholesale markets, the net cost becomes \$338.14/MW-day. By comparison, the "Net CONE" value for the PJM estimated "net cost of new entry" was \$171.40/MW-day for this time frame when the RPM price was struck[1]. Net CONE is the carrying cost for a new gas combustion turbine peaker, reduced by the energy margins such a unit would have earned on average in the prior three years at actual PJM spot prices.

These discrepancies between AEP Ohio's embedded cost, and Net CONE and RPM prices will become larger in the next two years, because RPM prices (including scaling factors) will be \$20.01/MW-day and \$33.71/MW-day for 2012/13 and 2013/2014 respectively while Net CONE values for these same planning years are \$276.09/MW-day and \$317.95/MW-day respectively (see direct testimony of Company witness Pearce at exhibit KDP-7).

Q. WHY IS THE PJM RPM PRICE SO MUCH LOWER THAN AEP OHIO'S EMBEDDED COSTS?

A. There are several reasons. First, AEP Ohio's cost reflects the average capital and fixed costs of its fleet of generation, which includes approximately 13,000 MW of plants of a variety of ages and technologies, but is largely comprised of baseload coal plants. The PJM price reflects the net cost of a gas peaker, which is a less capital-intensive type of generation than most of AEP Ohio's fleet. Second, the PJM RPM price moves up or down relative to a peaker's cost depending on how much capacity is available in the PJM market, what bid prices are offered by generators and other resources, and the location of the demand curve. That is, it

[1] See testimony of Company witness Pearce for details on these cost calculations.

reflects the marginal value of capacity as it was expected/set three years ago, when the PJM auction for 2011/12 capacity obligations was conducted in 2008. To the extent there was excess supply offered in that auction compared to PJM's target reserve margins, resulting capacity prices will be low, often much below Net CONE. For 2011/12, the auction cleared at slightly over an 18% reserve margin. The available capacity through 2014/15 exceeds planning reserve targets, contributing to low RPM prices. For the past several years, RPM prices have been below Net CONE largely because the kinds of capacity that have been attracted to participating in RPM auctions have been mostly plant life extensions and capacity upgrades, demand-response resources and expanded transmission capacity -- all of which tend to cost less per MW than a new plant (and especially, less than a baseload coal plant). Further, load growth (hence need for capacity) was reduced due to the economic downturn.

The kinds of incremental capacity resources that RPM has attracted are sufficient for maintaining reliability over the next few years (which is precisely what PJM intended), but they are not necessarily the same kinds of resources that would be preferred for long term resource planning that is focused on minimizing lifecycle costs of power, risks, and addressing other kinds of social policy considerations. AEP Ohio's resources were chosen in the latter context, hence are much different in character and carrying costs.

Retail providers would understandably like to have AEP Ohio provide capacity at as low a cost as possible, so they are advocating the PJM RPM price basis be required. However, as explained below, this would not be compensatory for AEP Ohio, which has a longer, more binding reliability obligation as a FRR utility than the CRES providers incur as short term Load Serving Entities (LSE). Thus, applying the RPM-based price would introduce an uneconomic bypass opportunity for CRES providers, at the expense of AEP Ohio customers and shareholders. While such bypass would undoubtedly increase the prevalence of retail providers in AEP Ohio's service territory in the short run, it would not be fostering efficient or durable competition. It is more likely that if market prices increase materially, CRES providers will turn their former AEP Ohio customers back to AEP Ohio as the default service provider.

Q. WHY DOES AEP OHIO NEED TO RECOVER ITS EMBEDDED CAPACITY COSTS FROM CRES PROVIDERS WHILE OTHER OHIO UTILITIES DO NOT?

A. In PJM, only AEP and Duke have elected to be FRR suppliers of capacity to their service territories (and Duke will not start serving in this role until January 2012). This means AEP Ohio is not a participant in PJM's RPM auctions or capacity procurement (except insofar as it has capacity not needed for its native load and its auction participation is limited to 1300 MW), but it still is obligated to PJM to provide long term capacity (5-year minimum commitment, initially) for all the load in its distribution franchise territories, regardless of whether those customers are new or old, or whether their energy supply comes from AEP Ohio or a third-party CRES provider. Concomitantly, CRES providers in AEP Ohio's territory must have previously notified PJM and AEP of their intentions to become FRR entities themselves for their expected retail loads and have obtained the needed capacity in prior bilateral procurements, or else they must buy capacity from AEP Ohio at the rates which are in dispute today.

Q. IF RETAIL SUPPLIERS WHO WISH TO BE SELLING ELECTRICITY IN AEP OHIO'S TERRITORY ALREADY COULD HAVE HAD ACCESS TO ALTERNATIVE CAPACITY IN PJM FOR 2011 AND BEYOND, WHY WOULD THEY NOT HAVE OBTAINED IT?

A. Apparently many did not choose to procure such capacity and import it into AEP Ohio's territory. This is understandable, for two reasons. First, they may have had few or no committed retail customers three years in advance; a shorter contracting horizon is more typical for retail electric services. Second, they may have been uncertain about the energy prices that would prevail in 2011 (which are the larger part of their overall cost of generation they could offer to retail customers), so they did not foresee the opportunity to sell retail services that has arisen with the recent decline in energy costs. However, short term market circumstances are now favorable, and as a result, they would now like to procure their capacity under current RPM prices.

ECONOMIC ISSUES IN CRES CAPACITY PRICING

Q. ABOVE, YOU SHOWED WHAT CRES PROVIDER'S COSTS WILL BE IF THE CAPACITY PORTION OF THE CRES PROVIDER'S BILL IS BASED ON RPM PRICES RATHER THAN AEP'S COSTS. WHY ISN'T THIS A DESIRABLE RESULT? IF THE CRES PROVIDER PASSED ON

THAT REDUCTION AND ITS SERVICES WOULD BE CHEAPER, SHOULDN'T CUSTOMERS HAVE ACCESS TO THAT SERVICE?

A. First, it is not assured that CRES providers would pass on the lower costs to customers, rather than keep most of the savings for themselves. But even if they did, this is not a desirable result from an overall economic viewpoint (even though it might seem like one to the customers of CRES providers), because customer switching (under RPM-based pricing) would not be occurring due to an actual economic advantage (or societal efficiency gain) in the supply of electric power service by those CRES providers (in lieu of AEP Ohio). Rather, it would simply involve the resale of AEP Ohio's capacity at a discount, subsidizing CRES *providers at the expense of AEP Ohio which would be taking a loss on the resale* of their existing capacity (potentially reallocating those shortfalls to non-shopping AEP Ohio customers). In essence, it would be an uneconomic bypass, not efficiency gains from true competition. For instance, being able to sell retail services based on RPM capacity costs will not induce CRES providers to take appropriate responsibility for their own capacity development/procurement in the future. To the contrary, it would encourage them to avoid such commitments, and it would give them the incentive and opportunity to become active sellers in years when RPM prices turn out to be below AEP Ohio's embedded costs, and not when the reverse occurs.

Q. WHY WOULD EXTENDING CAPACITY TO CRES PROVIDERS AT RPM-BASED PRICES CREATE A FINANCIAL LOSS FOR AEP?

Absent the recovery mechanism AEP Ohio has proposed, it only collects its cost of capacity from retail customers to the extent they are non-shopping customers. If customers switch to a CRES provider, AEP Ohio is still liable for their capacity needs. Embedded in AEP Ohio's retail rates are the same costs it is requesting FERC to approve for its capacity resale to CRES providers (except insofar as a cost-indexed formula is used for the CRES rate).

Q. IF CUSTOMERS WERE TO SWITCH TO A CRES PROVIDER THAT COULD USE AEP CAPACITY AT RPM-BASED PRICES, WOULD AEP SIMPLY INCUR A LOSS EQUAL TO THE DIFFERENCE BETWEEN ITS EMBEDDED CAPACITY COSTS AND THE RPM-BASED PRICE, OR WOULD THERE BE OFFSETTING SAVINGS OR MARKET OPPORTUNITIES TO MITIGATE THE LOSS?

A. If customers leave for a CRES provider, AEP Ohio would be relieved of its obligation to provide the energy supply component of electricity service to those customers. This means it could resell the energy that would have otherwise been needed at the PJM LMP price for locally produced power. After subtracting out the average production costs, AEP Ohio would have net operating margins which partially offset its need to recover the full embedded cost of the released capacity. Of course, the prices and quantities of these wholesale market energy revenues are highly uncertain and circumstantial.

Q. IF THE COMMISSION DOES INCLUDE ENERGY CREDITS, SHOULD IT CONSIDER PUTTING A LIMIT OR FLOOR ON THE OFFSETTING ENERGY CREDITS IN THE CALCULATION OF ITS NET CAPACITY CHARGE?

A. Yes, I also understand that AEP Ohio is recommending limitations on any such energy credit mechanism, as discussed by Company witness Pearce. The concern is that energy operating margins could become occasionally so high that if fully deducted, the net capacity costs would become negative. In that situation, AEP would be paying the CRES to take its capacity, thereby effectively giving all of the value of offsystem wholesale margins to the CRES providers. This would create a perverse situation in which the CRES provider could enjoy wholesale energy savings benefits from netback capacity prices, even though it was not participating in wholesale markets at all, and even though it did not provide any of the initial capital investment or managerial acumen to build, maintain, or market that generation whose energy happened to be deep in the money.

Q. SHOULD THE COMMISSION BE CONCERNED THAT THERE LIKELY WOULD BE LESS CRES PROVIDER ACTIVITY IN THE AEP OHIO SERVICE TERRITORY UNDER AEP OHIO'S PROPOSAL THAN WITH RPM-BASED PRICES FOR CAPACITY?

A. No, the focus should be on fairness and on genuine competition, not just entry by CRES providers. It is very likely that there would be less near-term CRES activity under AEP Ohio's proposal, but this is not a basis for concluding there would be adverse impacts on bonafide retail competition from approving the cost-based rates AEP Ohio has requested. The chance that there may be less CRES activity under AEP Ohio's proposal than under RPM pricing is not the appropriate focus. If AEP Ohio charged nothing at all for its capacity to CRES providers, that would encourage even more CRES entrants to the regional market. But that establishes a market of free riders, not one of more capable suppliers having truly lower costs or superior service. The AEP Ohio embedded rates are currently higher than the RPM-based prices, hence undoubtedly less advantageous to CRES providers than RPM-based charges, but that is not the same as saying there would be harm to <u>competition</u> from charging the AEP Ohio formula rates. AEP Ohio should not be put in a position where it has to subsidize its competitors in order to "foster competition." Such competition would be entirely artificial and only sustainable to the continuing extent of the subsidy. Bonafide competitors should have to take over the service obligation to their customers on comparable terms to the way AEP provides that service today, i.e., with a long term commitment for their capacity adequacy.

Simply fostering retail competition for its own sake, especially if success is measured in terms of how many customers have switched away from a utility default provider, is not an appropriate or informative metric of economic benefit or efficiency. Increasing customer switching to CRES providers could be achieved in numerous ways that have no social economic benefit whatsoever, except to the retail providers themselves. For instance, a huge surcharge could be added to the default service charge in order to make it easier for CRES providers to beat the default price. This would attract CRES entrants, but again not because they have a true lower cost of providing the service. Rather, it would be because of a wealth transfer or subsidy involved to improve their position relative to other participants.

Q. WOULD THERE BE ADVERSE, UNECONOMIC CONSEQUENCES FROM IMPLEMENTING RPM-BASED CAPACITY PRICING?

A. Yes, I think that is likely. Reliability in a power pool is inherently a public good, which tends to invite "free-riders". That is, if one party provides capacity resources needed for reliability to its customers but cannot restrict those reliability benefits to just its own customers (e.g., due to Kirchoff's Laws of electricity flow on an interconnected network), then other suppliers and customers automatically benefit. This tends to create an incentive to let others solve the capacity development problem/obligation. Precisely for that reason, PJM (and other reliability monitoring agencies) imposes a pro rata requirement on <u>all</u> LSEs to supply or obtain capacity on equivalent terms, to the same extent, or else they cannot gain the benefits of pool membership. The CRES proposal effectively asks that they be allowed to be partial LSEs, not providing capacity over the same horizon as AEP Ohio or even other retail service providers (e.g. in default service auctions). They simply want to rent the capacity that others are paying for on a shorter term basis, at currently low RPM rates.

If CRES providers gained access to AEP Ohio's capacity at RPM-based rates, they would have little or no incentive to contract forward for capacity in the future, in a manner that would actually signal their need and willingness to pay for it to potential developers. To the contrary, they would be being rewarded and encouraged to wait. Similarly, AEP Ohio would now be bearing a disincentive to develop future capacity, because it would know that there are future "free-riders" waiting and expecting to pay less than cost for it.

Q. DO YOU BELIEVE THE RPM-BASED PRICING ADVOCATED BY CRES PROVIDERS IS OPPORTUNISTIC AND WOULD NOT BE SOUGHT UNDER DIFFERENT MARKET CIRCUMSTANCES?

A. Yes, I do. If AEP Ohio's embedded rate was below the RPM-based rate, as could happen in a tight market, it is very hard to imagine that CRES providers would be insisting on paying the RPM-based rate rather than having access to the then-low AEP Ohio embedded rate. They are clearly seeking a "lower of cost or market" rate under circumstances where the market price happens to be the lower of the two.

Q. IS THERE A NEED FOR CAPACITY EXPANSION IN THE AEP REGION OF PJM AT THIS TIME, AND DOES THIS AFFECT WHETHER IT IS MORE APPROPRIATE TO USE RPM PRICES THAN AEP OHIO'S EMBEDDED COSTS?

A. Right now, and perhaps even for the next several years, there is no apparent need for new capacity in and around AEP or much of PJM, at least in regard to maintaining adequate reliability; regional reserve margins are generally above planning targets. There may be other reasonable motives and opportunities for expanding or changing the capacity mix in PJM, but those considerations are not reflected in, nor fostered by, the RPM price, and they will not be differentially satisfied by CRES providers facing RPM prices rather than embedded costs.

However, it is possible that pending EPA regulations may induce coal plant retirements that create a new, longer term and larger need for capacity expansion than the RPM market yet reflects or can respond to.

Q. WHAT ABOUT THE EFFICIENCY OF PRICES SEEN BY GENERATION CUSTOMERS?

A. Customers of AEP Ohio are not seeing the short run prices of capacity in their retail service. Instead, they are seeing average costs as appropriate. However, the underlying resources were chosen in a process that considered the best available long-term solutions at the time they were built, and in fact the overall effect of those choices is that AEP Ohio generation has been mostly comparable to or cheaper than the PJM market for the past several years. This is not efficient, but it is attractive to customers and at the same time fair to AEP's investors, who are enjoying reliable cost recovery for having put those resources in place.

Q. THE EFFICIENCY OF THE PRICE FACING SHOPPING CUSTOMERS DOES SEEM TO DEPEND ON WHETHER RPM OR EMBEDDED COSTS ARE USED, CORRECT?

A. Yes, that is correct, but only partially so, as the overall efficiency also depends on how customers are charged for the costs of the risks to AEP Ohio for customers' ability to shop and return to default service. That is, shopping customers would see the most efficient price, in principle, if it was a combination of the PJM RPM-based price for capacity plus market energy costs (LMPs plus adders for losses, transmission congestion, and other services as needed for load following and risk management). However, they would be gaining access to that exercise that choice opportunistically – the "lower of cost or market" choice described previously. Recognizing this, AEP Ohio has designed an option-based POLR surcharge to compensate it for the cost of the risk to AEP Ohio for customer's ability to shop and return to default service that assumes the capacity costs to CRES providers will be the proposed embedded cost rate. These POLR rights would be much more costly if the switching options had been priced based on the RPM-based capacity prices.[2]

Q. DOES THE USE OF FORMULA RATES FOR SETTING THE EMBEDDED COST OF AEP OHIO'S CAPACITY TO CRES PROVIDERS CREATE ANY UNDUE TRANSFER OF RISKS OR INCENTIVES THAT COULD DISTORT WHOLESALE GENERATION MARKETS?

A. I believe the question of whether a formula rate is appropriate for AEP Ohio's situation is a separate question from whether CRES providers should have access to AEP Ohio's capacity at embedded costs. I have not reviewed the terms of the proposed formula in detail, though I am aware of its general nature. It is correct to observe that merchant generation companies (who do not have a franchise load under embedded rates for selling their output) do not have a comparable mechanism for recovering their costs of generation capital and operating costs, or any changes to those costs that may arise from shifting regulations or market conditions. This provides a certain degree of financial advantage to AEP Ohio's generation, and embedded pricing to CRES providers continues that advantage.

[2] It is important to appreciate that this POLR option charge in no way covers the capacity costs of supporting retail customers. It is solely related to the cost of risk that is intrinsic to customers enjoying the right to opportunistically choose the lower cost of two alternatives.

However, it is also true that the unregulated generation companies enjoy some advantages and flexibilities in power supply and pricing that AEP Ohio's generation does not. In particular, merchant generators do not have an obligation to serve beyond the extent to which they voluntarily contract forward. If market conditions become unattractive (e.g, if fuel costs rise, or environmental compliance upgrades are too costly to complete and remain profitable in the wholesale markets), they can retire units and not replace them. That is, they do not need to build unless or until market prices are attractive. And under those circumstances, the market price of power may also rise as much or more than the operating costs on their existing infra-marginal units, allowing them to harvest large profits. This is a risky situation, but they do have the possibility of large upside gains in tight markets that AEP Ohio does not enjoy under its cost of service arrangements – and such gains might be substantial for a company like AEP Ohio with many baseload units having low operating costs. Overall, this does mean there are differences in risks, incentives and opportunities facing AEP Ohio compared to merchant generators, but those differences arise because the AEP Ohio generation faces different obligations and constraints as well.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS.

A. I conclude that the proposed use of embedded costs for AEP Ohio's CRES capacity rate is just and reasonable, and that its approval would have no adverse impacts on efficient retail competition. In contrast, the proposed RPM-based rate would simply entail AEP Ohio being forced to subsidize its own bypass.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

APPENDIX A

Mr. Frank Graves is a Principal of *The Brattle Group* who specializes in regulatory and financial economics, especially for electric and gas utilities. He has assisted utilities in forecasting, valuation, and risk analysis of many kinds of long range planning and service design decisions, such as generation and network capacity expansion, supply procurement and cost recovery mechanisms, network flow modeling, renewable asset selection and contracting, and hedging strategies. He also provides consulting and expert witness support for commercial litigation matters, such as contract disputes and securities fraud proceedings. He has testified before the FERC and many state regulatory commissions, as well as in state and federal courts, on such matters as integrated resource planning (IRPs), the prudence of prior investment and contracting decisions, costs and benefits of new services, policy options for industry restructuring, adequacy of market competition, and competitive implications of proposed mergers and acquisitions.

In the area of financial economics, he has assisted and testified for companies in regard to contract damages estimation, securities litigation suits, special purpose audits, tax disputes, risk management, and cost of capital estimation.

He received an M.S. with a concentration in finance from the M.I.T. Sloan School of Management in 1980, and a B.A. in Mathematics from Indiana University in 1975.

AREAS OF EXPERTISE

- *Utility Planning and Operations*
- *Regulated Industry Restructuring*
- *Market Competition*
- *Electric and Gas Transmission*
- *Financial Analysis*

EXPERIENCE

Utility Planning and Operations

- Air quality and other power plant environmental regulations are being tightened considerably in the period from about 2014-2018. Mr. Graves has co-developed a market and financial model for determining what power plants are most likely to retire vs. retrofit with new environmental controls, and how much this may alter their profitability. This has been used to help several power market participants assess future capacity needs, as well as to adjust their price forecasts for the coming decade.

- Merchant power plant development and financing depends in part on obtaining a long term power purchase agreement. Mr. Graves directed a study of what pricing points and risk-sharing terms should be attractive to potential buyers of long-term power supply contracts from a large baseload facility.

- Many utilities are pursuing smart meters and time-of-use pricing to increase customer ability to consume electricity economically. Mr. Graves has led a study of the costs and benefits of different scales and timing of installation of such meters, to determine the appropriate pace. He has also evaluated how various customer incentives to increase conservation and demand response might be provided over the internet, and how much they might increase the participation rates in smart meter programs.

- Wind resources are becoming a critical part of the generation expansion plans and contracting interests of many utilities, in order to satisfy renewable portfolio standards and to reduce long run exposure to carbon prices and fuel cost uncertainty. Mr. Graves has applied *Brattle*'s risk modeling capabilities to simulate the impacts of wind resources on the potential range of costs for portfolios of wholesale power contracts designed to serve retail electricity loads. He has also assessed the amount and costs of additional ancillary services that may be required to successfully integrate large quantities of wind generation on the transmission grid.

- The potential introduction of environmental restrictions or fees for CO_2 emissions has made generation expansion decisions much more complex and risky. He helped one utility assess these risks in regard to a planned baseload coal plant, finding that the value of flexibility in other technologies was high enough to prefer not building a conventional coal plant.

- Mr. Graves helped design, implement, and gain regulatory approvals for a natural gas procurement hedging program for a western U.S. gas and electric utility. A model of how gas forward prices evolve over time was estimated and combined with a statistical model of the term structure of gas volatility to simulate the uncertainty in the annual cost of gas at various times during its procurement, and the resulting impact on the range of potential customer costs.

- Generation planning for utilities has become very complex and risky due to high natural gas prices and potential CO2 restrictions of emission allowances. Some of the scenarios that must be considered would radically alter system operations relative to current patterns of use. Mr. Graves has assisted utilities with long range planning for how to measure and cope with these risks, including how to build and value contingency plans in their resource selection criteria, and what kinds of regulatory communications to pursue to manage expectations in this difficult environment.

- Several utilities with coal-fired power plants have faced allegations from the U.S. EPA that they have conducted past maintenance on these plants which should be deemed "major modifications", thereby triggering New Source Review standards for air quality controls. Mr. Graves has helped one such utility assess limitations on the way in which GADS data can be used retrospectively to quantify comparisons between past actual and projected future emissions. For another utility, Mr. Graves developed retrospective estimates of changes in emissions before and after repairs using production costing simulations. In a third, he reviewed contemporaneous corporate planning documents to show that no increase in emissions would have been expected from the repairs, due to projected reductions in future use of the plant as well as higher efficiency. In all three cases, testimony was presented.

- The U.S. Government is contractually obligated to dispose of spent nuclear fuel at commercial reactors after January 1998, but it has not fulfilled this duty. As a result, nuclear facilities that are shutdown or facing full spent fuel pools are facing burdensome costs and risks. Mr. Graves prepared developed an economic model of the performance that could have reasonably been expected of the government, had it not breached its contract to remove the spent fuel.

- Capturing the full value of hydroelectric generation assets in a competitive power market is heavily dependent on operating practices that astutely shift between real power and ancillary services markets, while still observing a host of non-electric hydrological constraints. Mr. Graves led studies for several major hydro generation owners in regard to forecasting of market conditions and corresponding hydro schedule optimization. He has also designed transfer pricing procedures that create an internal market for diverting hydro assets from real power to system support services firms that do not yet have explicit, observable market prices.

- Mr. Graves led a gas distribution company in the development of an incentive ratemaking system to replace all aspects of its traditional cost of service regulation. The base rates (for non-fuel operating and capital costs) were indexed on a price-cap basis (RPI-X), while the gas and upstream transportation costs allowances were tied to optimal average annual usage of a reference portfolio of supply and transportation contracts. The gas program also included numerous adjustments to the gas company's rate design, such as designing new standby rates so that customer choice will not be distorted by pricing inefficiencies.

- An electric utility with several out-of-market independent power contracts wanted to determine the value of making those plants dispatchable and to devise a negotiating strategy for restructuring the IPP agreements. Mr. Graves developed a range of forecasts for the delivered price of natural gas to this area of the country. Alternative ways of sharing the potential dispatch savings were proposed as incentives for the IPPs to renegotiate their utility contracts.

- For an electric utility considering the conversion of some large oil-fired units to natural gas, Mr. Graves conducted a study of the advantages of alternative means of obtaining gas supplies and gas transportation services. A combination of monthly and daily spot gas supplies, interruptible pipeline transportation over several routes, gas storage services, and "swing" (contingent) supply contracts with gas marketers was shown to be attractive. Testimony was presented on why the additional services of a local distribution company would be unneeded and uneconomic.

- A power engineering firm entered into a contract to provide operations and maintenance services for a cogenerator, with incentives fees tied to the unit's availability and operating cost. When the fees increased due to changes in the electric utility tariff to which they were tied, a dispute arose. Mr. Graves provided analysis and testimony on the avoided costs associated with improved cogeneration performance under a variety of economic scenarios and under several alternative utility tariffs.

- Mr. Graves has helped several pipelines design incentive pricing mechanisms for recovering their expected costs and reducing their regulatory burdens. Among these have been Automatic Rate Adjustment Mechanisms (ARAMs) for indexation of operations and maintenance expenses, construction-cost variance-sharing for routine capital expenditures that included a procedure for eliciting unbiased estimates of future costs, and market-based prices capped at replacement costs when near-term future expansion was an uncertain but probable need.

- For a major industrial gas user, he prepared a critique of the transportation balancing charges proposed by the local gas distribution company. Those charges were shown to be arbitrarily sensitive to the measurement period as well as to inconsistent attribution of storage versus replacement supply costs to imbalance volumes. Alternative balancing valuation and accounting methods were shown to be cheaper, more efficient, and simpler to administer. This analysis helped the parties reach a settlement based on a cash-in/cash-out design.

- The Clean Air Act Amendments authorized electric utilities to trade emission allowances (EAs) as part of their approach to complying with SO_2 emissions reductions targets. For the Electric Power Research Institute (EPRI), Mr. Graves developed multi-stage planning models to illustrate how the considerable uncertainty surrounding future EA prices justifies waiting to invest in irreversible control technologies, such as scrubbers or SCRs, until the present value cost of such investments is significantly below that projected from relying on EAs.

- For an electric utility with a troubled nuclear plant, Mr. Graves presented testimony on the economic benefits likely to ensue from a major reorganization. The plant was to be spun off to a jointly-owned subsidiary that would sell available energy back to the original owner under a contract indexed to industry unit cost experience. This proposal afforded a considerable reduction of risk to ratepayers in exchange for a reasonable, but highly uncertain prospect of profits for new investors. Testimony compared the incentive benefits and potential conflicts under this arrangement to the outcomes foreseeable from more conventional incentive ratemaking arrangements.

- Mr. Graves helped design Gas Inventory Charge (GIC) tariffs for interstate pipelines seeking to reduce their risks of not recovering the full costs of multi-year gas supply contracts. The costs of holding supplies in anticipation of future, uncertain demand were evaluated with models of the pipeline's supply portfolio that reveal how many non-production costs (demand charges, take-or-pay penalties, reservation fees, or remarketing costs for released gas) would accrue under a range of demand scenarios. The expected present value of these costs provided a basis for the GIC tariff.

- Mr. Graves performed a review and critique of a state energy commission's assessment of regional natural gas and electric power markets in order to determine what kinds of pipeline expansion into the area was economic. A proposed facility under review for regulatory approval was found to depend strongly on uneconomic bypass of existing pipelines and LDCs. In testimony, modular expansion of existing pipelines was shown to have significantly lower costs and risks.

- For several electric utilities with generation capacity in excess of target reserve margins, Mr. Graves designed and supervised market analyses to identify resale opportunities by comparing the marginal operating costs of all this company's power plants not needed to meet target reserves to the marginal costs for almost 100 neighboring utilities. These cost curves were then overlaid on the corresponding curve for the client utility to identify which neighbors were competitors and which were potential customers. The strength of their relative threat or attractiveness could be quantified by the present value of the product of the amount, duration, and differential cost of capacity that was displaceable by the client utility.

- Mr. Graves specified algorithms for the enhancement of the EPRI EGEAS generation expansion optimization model, to capture the first-order effects of financial and regulatory constraints on the preferred generation mix.

- For a major electric power wholesaler, Mr. Graves developed a framework for estimating how pricing policies affect the relative attractiveness of capacity expansion alternatives. Traditional cost-recovery pricing rules can significantly distort the choice between two otherwise equivalent capacity plans, if one includes a severe "front end load" while the other does not. Price-demand feedback loops in simulation models and quantification of consumer satisfaction measures were used to appraise the problem. This "value of service" framework was generalized for the Electric Power Research Institute.

- For a large gas and electric utility, Mr. Graves participated in coordinating and evaluating the design of a strategic and operational planning system. This included computer models of all aspects of utility operations, from demand forecasting through generation planning to financing and rate design. Efforts were split between technical contributions to model design and attention to organizational priorities and behavioral norms with which the system had to be compatible.

- For an oil and gas exploration and production firm, Mr. Graves developed a framework for identifying what industry groups were most likely to be interested in natural gas supply contracts featuring atypical risk-sharing provisions. These provisions, such as price indexing or performance requirements contingent on market conditions, are a form of product differentiation for the producer, allowing it to obtain a price premium for the insurance-like services.

- For a natural gas distribution company, Mr. Graves established procedures for redefining customer classes and for repricing gas services according to customers' similarities in load shape, access to alternative gas supplies, expected growth, and need for reliability. In this manner, natural gas service was effectively differentiated into several products, each with price and risk appropriate to a specific market. Planning tools were developed for balancing gas portfolios to customer group demands.

- For a Midwestern electric utility, Mr. Graves extended a regulatory *pro forma* financial model to capture the contractual and tax implications of canceling and writing off a nuclear power plant in mid-construction. This possibility was then appraised relative to completion or substitution alternatives from the viewpoints of shareholders (market value of common equity) and ratepayers (present value of revenue requirements).

- For a corporate venture capital group, Mr. Graves conducted a market-risk assessment of investing in a gas exploration and production company with contracts to an interstate pipeline. The pipeline's market growth, competitive strength, alternative suppliers, and regulatory exposure were appraised to determine whether its future would support the purchase volumes needed to make the venture attractive.

- For a natural gas production and distribution company, he developed a strategic plan to integrate the company's functional policies and to reposition its operations for the next five years. Decision analysis concepts were combined with marginal cost estimation and financial *pro forma* simulation to identify attractive and resilient alternatives. Recommendations included target markets, supply sources, capital budget constraints, rate design, and a planning system. A two-day planning conference was conducted with the client's executives to refine and internalize the strategy.

- For the New Mexico Public Service Commission, he analyzed the merits of a corporate reorganization of the major New Mexico gas production and distribution company. State ownership of the company as a large public utility was considered but rejected on concerns over efficiency and the burdening of performance risks onto state and local taxpayers.

Regulated Industry Restructuring

- For several utilities facing the end of transitional "provider of last resort" (or POLR) prices, Mr. Graves developed forecasts and risk analyses of alternative procurement mechanisms for follow-on POLR contracts. He compared portfolio risk management approaches to full requirements outsourcing under various terms and conditions.

- For a large municipal electric and gas company considering whether to opt-in to state retail access programs, Mr. Graves lead an analysis of what changes in the level and volatility of customer rates would likely occur, what transition mechanisms would be required, and what impacts this would have on city revenues earned as a portion of local electric and gas service charges.

- Many utilities experienced significant "rate shock" when they ended "rate freeze" transition periods that had been implemented with earlier retail restructuring. The adverse customer and political reactions have lead to proposals to annual procurement auctions and to return to utility-owned or managed supply portfolios. Mr. Graves has assisted utilities and wholesale gencos with analyses of whether alternative supply procurement arrangements could be beneficial.

- The impacts of transmission open access and wholesale competition on electric generators risks and financial health are well documented. In addition, there are substantial impacts on fuel suppliers, due to revised dispatch, repowerings and retirements, changes in expansion mix, altered load shapes and load growth under more competitive pricing. For EPRI, Mr. Graves co-authored a study that projected changes in fuel use within and between ten large power market regions spanning the country under different scenarios for the pace and success of restructuring.

- As a result of vertical unbundling, many utilities must procure a substantial portion of their power from resources they do not own or operate. Market prices for such supplies are quite volatile. In addition, utilities may face future customer switching to or from their supply service, especially if they are acting as provider of last resort (POLR). This problem is a blending of risk management with the traditional least-cost Integrated Resource Planning (IRP). Regulatory standards for findings of prudence in such a hybrid environment are often not well understood or articulated, leaving utilities at risk for cost disallowances that can jeopardize their credit-worthiness. Mr. Graves has assisted several utilities in devising updated procurement mechanisms, hedging strategies, and associated regulatory guidelines that clarify the conditions for approval and cost recovery of resource plans, in order to make possible the expedited procurement of power from wholesale market suppliers.

- Public power authorities and cooperatives face risks from wholesale restructuring if their sales-for-resale customers are free to switch to or from supply contracting with other wholesale suppliers. Such switching can create difficulties in servicing the significant debt capitalization of these public power entities, as well as equitable problems with respect to non-switching customers. Mr. Graves has lead analyses of this problem, and has designed alternative product pricing, switching terms and conditions, and debt capitalization policies to cope with the risks.

- As a means of unbundling to retain ownership but not control of generation, some utilities turned to divesting output contracts. Mr. Graves was involved in the design and approval of such agreements for a utility's fleet of generation. The work entailed estimating and projecting cost functions that were likely to track the future marginal and total costs of the units and analysis of the financial risks the plant operator would bear from the output pricing formula. Testimony on risks under this form of restructuring was presented.

- Mr. Graves contributed to the design and pricing of unbundled services on several natural gas pipelines. To identify attractive alternatives, the marginal costs of possible changes in a pipeline's service mix were quantified by simulating the least-cost operating practices subject to the network's physical and contractual constraints. Such analysis helped one pipeline to justify a zone-based rate design for its firm transportation service. Another pipeline used this technique to demonstrate that unintended degradations of system performance and increased costs could ensue from certain proposed unbundlings that were insensitive to system operations.

- For several natural gas pipeline companies, Mr. Graves evaluated the cost of equity capital in light of the requirements of FERC Order 636 to unbundle and reprice pipeline services. In addition to traditional DCF and risk positioning studies, the risk implications of different degrees of financial leverage (debt capitalization) were modeled and quantified. Aspects of rate design and cost allocation between services that also affect pipeline risk were considered.

- Mr. Graves assisted several utilities in forecasting market prices, revenues, and risks for generation assets being shifted from regulated cost recovery to competitive, deregulated wholesale power markets. Such studies have facilitated planning decisions, such as whether to divest generation or retain it, and they have been used as the basis for quantifying stranded costs associated with restructuring in regulatory hearings. Mr. Graves has assisted a leasing company with analyses of the tax-legitimacy of complex leasing transactions by reviewing the extent and quality of due diligence pursued by the lessor, the adequacy of pre-tax returns, the character, time pattern, and degree of risk borne by the buyer (lessor), the extent of defeasance, and compliance with prevailing guidelines for true-lease status.

Market Competition

- Mr. Graves has testified on the quality of retail competition in Pennsylvania and on whether various proposals for altering Default Service might create more robust competition.

- Regulatory and legal approvals of utility mergers require evidence that the combined entity will not have undue market power. Mr. Graves assisted several utilities in evaluating the competitive impacts of potential mergers and acquisitions. He has identified ways in which transmission constraints reduce the number and type of suppliers, along with mechanisms for incorporating physical flow limits in FERC's Delivered Price Test (DPT) for mergers. He has also assessed the adequacy of mitigation measures (divestitures and conduct restrictions) under the DPT, Market-Based Rates, and other tests of potential market power arising from proposed mergers.

- A major concern associated with electric utility industry restructuring is whether or not generation markets are adequately competitive. Because of the state-dependent nature of transmission transfer capability between regions, itself a function of generation use, the quality of competition in the wholesale generation markets can vary significantly and may be susceptible to market power abuse by dominant suppliers. Mr. Graves helped one of the largest ISOs in the U.S. develop market monitoring procedures to detect and discourage market manipulations that would impair competition.

- Vertical market power arises when sufficient control of an upstream market creates a competitive advantage in a downstream market. It is possible for this problem to arise in power supply, in settings where the likely marginal generation is dependent on very few fuel suppliers who also have economic interests in the local generation market. Mr. Graves analyzed this problem in the context of the California gas and electric markets and filed testimony to explain the magnitude and manifestations of the problem.

- The increased use of transmission congestion pricing has created interest in merchant transmission facilities. Mr. Graves assisted a developer with testimony on the potential impacts of a proposed line on market competition for transmission services and adjacent generation markets. He also assisted in the design of the process for soliciting and ranking bids to buy tranches of capacity over the line.

- Many regions have misgivings about whether the preconditions for retail electric access are truly in place. In one such region, Mr. Graves assisted a group of industrial customers with a critique of retail restructuring proposals to demonstrate that the locally weak transmission grid made adequate competition among numerous generation suppliers very implausible.

- Mr. Graves assisted one of the early ISOs with its initial market performance assessment and its design of market monitoring tests for diagnosing the quality of prevailing competition.

Electric and Gas Transmission

- Substantial fleets of wind-based generation can impose significant integration costs on power systems. Mr. Graves assisted in assessing what additional amounts and costs for ancillary services would be needed for a large Western utility.

- For a utility seeking FERC approval for the purchase of an affiliate's generating facility, Mr. Graves analyzed how transmission constraints affecting alternative supply resources altered their usefulness to the buyer.

- As part of a generation capacity planning study, he lead an analysis of how congestion premiums and discounts relative to locational marginal prices (LMPs) at load centers affected the attractiveness of different potential locations for new generation. At issue was whether the prevailing LMP differences would be stable over time, as new transmission facilities were completed, and whether new plants could exacerbate existing differentials and lead to degraded market value at other plants.

- Mr. Graves assisted a genco with its involvement in the negotiation and settlement of "regional through and out rates" (RTOR) that were to be abolished when MISO joined PJM. His team analyzed the distribution of cost impacts from several competing proposals, and they commented on administrative difficulties or advantages associated with each.

- For the electric utility regulatory commission of Colombia, S.A., Mr. Graves led a study to assess the inadequacies in the physical capabilities and economic incentives to manage voltages at adequate levels. The *Brattle* team developed minimum reactive power support obligations and supplement reactive power acquisition mechanisms for generators, transmission companies, and distribution companies.

- Mr. Graves conducted a cost-of-service analysis for the pricing of ancillary services provided by the New York Power Authority.

- On behalf of the Electric Power Research Institute (EPRI), Mr. Graves wrote a primer on how to define and measure the cost of electric utility transmission services for better planning, pricing, and regulatory policies. The text covers the basic electrical engineering of power circuits, utility practices to exploit transmission economies of scale, means of assuring system stability, economic dispatch subject to transmission constraints, and the estimation of marginal costs of transmission. The implications for a variety of policy issues are also discussed.

- The natural gas pipeline industry is wedged between competitive gas production and competitive resale of gas delivered to end users. In principle, the resulting basis differentials between locations around the pipeline ought to provide efficient usage and expansion signals, but traditional pricing rules prevent the pipeline companies from participating in the marginal value of their own services. Mr. Graves worked to develop alternative pricing mechanisms and service mixes for pipelines that would provide more dynamically efficient signals and incentives.

- Mr. Graves analyzed the spatial and temporal patterns of marginal costs on gas and electric utility transmission networks using optimization models of production costs and network flows. These results were used by one natural gas transmission company to design receipt-point-based transmission service tariffs, and by another to demonstrate the incremental costs and uneven distribution of impacts on customers that would result from a proposed unbundling of services.

Financial Analysis

- Holding company utilities with many subsidiaries in different states face differing kinds of regulatory allowances, balancing accounts with differing lags and allowed returns for cost recovery, possibly different capital structures, as well as different (and varying) operating conditions. Given such heterogeneity, it can be difficult to determine which subsidiaries are performing well vs. poorly relative to their regulatory and operational challenges. Mr. Graves developed a set of financial reporting normalization adjustments to isolate how much of each subsidiary's profitability was due to financial, vs. managerial, vs. non-recurring operational conditions, so that meaningful performance appraisal was possible.

- Many banks, insurance firms and capital management subsidiaries of large multinational corporations have entered into long term, cross border leases of properties under sale and leaseback or lease in, lease out terms. These have been deemed to be unacceptable tax shelters by the IRS, but that is an appealable claim. Mr. Graves has assisted several companies in evaluating whether their cross border leases had legitimate business purpose and economic substance, above and beyond their tax benefits, due to likelihood of potentially facing a role as equityholder with ownership risks and rewards. He has shown that this is a case-specific matter, not per se determined by the general character of these transactions.

- Many utilities have regulated and unregulated subsidiaries, which face different types and degrees of risk. Mr. Graves lead a study of the appropriate adjustments to corporate hurdle rates for the various lines of business of a utility with many types of operations.

- A company that incurred Windfall Tax liabilities in the U.K. regarded those taxes as creditable against U.S. income taxes, but this was disputed by the IRS. Mr. Graves lead a team that prepared reports and testimony on why the Windfall Tax had the character of a typical excess profits tax, and so should be deemed creditable in the U.S. The tax courts concurred with this opinion and allowed the claimed tax deductions in full.

- For a defendant in a sentencing hearing for securities' fraud, Mr. Graves prepared an analysis of how the defendant's role in the corporate crisis was confounded by other concurrent events and disclosures that made loss calculations unreliable. At trial, the Government stipulated that it agreed with Mr. Graves' analysis.

- For the U.S. Department of Justice, Mr. Graves prepared an event study quantifying bounds on the economic harm to shareholders that had likely ensued from revelations that Dynegy Corporation's "Project Alpha" had been improperly represented as a source of operating income rather than as a financing. The event study was presented in the re-sentencing hearing of Mr. Jamie Olis, the primary architect of Project Alpha.

- Mr. Graves has assisted leasing companies with analyses of the tax-legitimacy of complex leasing transactions. These analyses involved reviewing the extent and quality of due diligence pursued by the lessor, the adequacy of pre-tax returns, the character, time pattern, and degree of risk borne by the buyer (lessor), the extent, purpose and cost of defeasance, and compliance with prevailing guidelines for true-lease status.

- For a utility facing significant financial losses from likely future costs of its Provider of Last Resort (POLR) obligations, Mr. Graves prepared an analysis of how optimal hindsight coverage would have compared in costs to a proposed restructuring of the obligation. He also reviewed the prudence of prior, actual coverage of the obligation in light of conventional risk management practices and prevailing market conditions of credit constraints and low long-term liquidity.

- Several banks were accused of aiding and abetting Enron's fraudulent schemes and were sued for damages. Mr. Graves analyzed how the stock market had reacted to one bank's equity analyst's reports endorsing Enron as a "buy," to determine if those reports induced statistically significant positive abnormal returns. He showed that individually and collectively they did not have such an effect.

- Mr. Graves lead an analysis of whether a corporate subsidiary had been effectively under the strategic and operational control of its parent, to such an extent that it was appropriate to "pierce the corporate veil" of limited liability. The analysis investigated the presence of untenable debt capitalization in the subsidiary, overlapping management staff, the adherence to normal corporate governance protocols, and other kinds of evidence of excessive parental control.

- As a tax-revenue enhancement measure, the IRS was considering a plan to recapture deferred taxes associated with generation assets that were divested or reorganized during state restructurings for retail access. Mr. Graves prepared a white paper demonstrating the unfairness and adverse consequences of such a plan, which was instrumental in eliminating the proposal.

- For a major electronic and semiconductor firm, Mr. Graves critiqued and refined a proposed procedure for ranking the attractiveness of research and development projects. Aspects of risk peculiar to research projects were emphasized over the standards used for budgeting an already proven commercial venture.

- In a dispute over damages from a prematurely terminated long-term power tolling contract, Mr. Graves presented evidence on why calculating the present value of those damages required the use of two distinct discount rates: one (a low rate) for the revenues lost under the low-risk terminated contract and another, much higher rate, for the valuation of the replacement revenues in the risky, short-term wholesale power markets. The amount of damages was dramatically larger under a two-discount rate calculation, which was the position adopted by the court.

- The energy and telecom industries have been plagued by allegations regarding trading and accounting misrepresentations, such as wash trades, manipulations of mark-to-market valuations, premature recognition of revenues, and improper use of off-balance sheet entities. In many cases, this conduct has preceded financial collapse and subsequent shareholder suits. Mr. Graves lead research on accounting and financial evidence, including event studies of the stock price movements around the time of the contested practices, and reconstruction of accounting and economic justifications for the way asset values and revenues were recorded.

- Dramatic natural gas price increases in the U.S. have put several natural gas and electric utilities in the position of having to counter claims that they should have hedged more of their fuel supplies at times in the past. Mr. Graves developed testimony to rebut this hindsight criticism and risk management techniques for fuel (and power) procurement for utilities to apply in the future to avoid prudence challenges.

- As a means of calculating its stranded costs, a utility used a partial spin-off of its generation assets to a company that had a minority ownership from public shareholders. A dispute arose as to whether this minority ownership might be depressing the stock price, if a "control premium" was being implicitly deducted from its value. Using event studies and structural analyses, Mr. Graves identified the key drivers of value for this partially spun-off subsidiary, and he showed that value was not being impaired by the operating, financial and strategic restrictions on the company. He also reviewed the financial economics literature on empirical evidence for control premiums, which he showed reinforced the view that no control premium de-valuation was likely to be affecting the stock.

- A large public power agency was concerned about its debt capacity in light of increasing competitive pressures to allow its resale customers to use alternative suppliers. Mr. Graves lead a team that developed an Economic Balance Sheet representation of the agency's electric assets and liabilities in market value terms, which was analyzed across several scenarios to determine safe levels of debt financing. In addition, new service pricing and upstream supply contracting arrangements were identified to help reduce risks.

- Wholesale generating companies intuitively realize that there are considerable differences in the financial risk of different kinds of power plant projects, depending on fuel type, length and duration of power purchase agreements, and tightness of local markets. However, they often are unaware of how if at all to adjust the hurdle rates applied to valuation and development decisions. Mr. Graves lead a Brattle analysis of risk-adjusted discount rates for generation; very substantial adjustments were found to be necessary.

- A major telecommunications firm was concerned about when and how to reenter the Pacific Rim for wireless ventures following the economic collapse of that region in 1997-99. Mr. Graves lead an engagement to identify prospective local partners with a governance structure that made it unlikely for them to divert capital from the venture if markets went soft. He also helped specify contracting and financing structures that create incentives for the venture to remain together should it face financial distress, while offering strong returns under good performance.

- There are many risks associated with operations in a foreign country, related to the stability of its currency, its macro economy, its foreign investment policies, and even its political system. Mr. Graves has assisted firms facing these new dimensions to assess the risks, identify strategic advantages, and choose an appropriate, risk-adjusted hurdle rate for the market conditions and contracting terms they will face.

- The glut of generation capacity that helped usher in electric industry restructuring in the US led to asset devaluations in many places, even where no retail access was allowed. In some cases, this has led to bankruptcy, especially of a few large rural electric cooperatives. Mr. Graves assisted one such coop with its long term financial modeling and rate design under its plan of reorganization, which was approved. Testimony was provided on cost-of-service justifications for the new generation and transmission prices, as well as on risks to the plan from potential environmental liabilities.

- Power plants often provide a significant contribution to the property tax revenues of the townships where they are located. A common valuation policy for such assets has been that they are worth at least their book value, because that is the foundation for their cost recovery under cost-of-service utility ratemaking. However, restructuring throws away that guarantee, requiring reappraisal of these assets. Traditional valuation methods, *e.g.*, based on the replacement costs of comparable assets, can be misleading because they do not consider market conditions. Mr. Graves testified on such matters on behalf of the owners of a small, out-of-market coal unit in Massachusetts.

- Stranded costs and out-of-market contracts from restructuring can affect municipalities and cooperatives as well as investor-owned utilities. Mr. Graves assisted one debt-financed utility in an evaluation of its possibilities for reorganization, refinancing, and re-engineering to improve financial health and to lower rates. Sale and leaseback of generation, fuel contract renegotiation, targeted downsizing, spin-off of transmission, and new marketing programs were among the many components of the proposed new business plan.

- As a means of reducing supply commitment risk, some utilities have solicited offers for power contracts that grant the right but not the obligation to take power at some future date at a predetermined price, in exchange for an initial option premium payment. Mr. Graves assisted several of these utilities in the development of valuation models for comparing the asking prices to fair market values for option contracts. In addition, he has helped these clients develop estimates of the critical option valuation parameters, such as trend, volatility, and correlations of the future prices of electric power and the various fuel indexes proposed for pricing the optional power.

- For the World Bank and several investor-owned electric utilities, Mr. Graves presented tutorial seminars on applying methods of financial economics to the evaluation of power production investments. Techniques for using option pricing to appraise the value of flexibility (such as arises from fuel switching capability or small plant size) were emphasized. He has applied these methods in estimating the value of contingent contract terms in fuel contracts (such as price caps and floors) for natural gas pipelines.

- Mr. Graves prepared a review of empirical evidence regarding the stock market's reaction to alternative dividend, stock repurchase, and stock dividend policies for a major electric utility. Tax effects, clientele shifting, signaling, and ability to sustain any new policies into the future were evaluated. A one-time stock repurchase, with careful announcement wording, was recommended.

- For a division of a large telecommunications firm, Mr. Graves assisted in a cost benchmarking study, in which the costs and management processes for billing, service order and inventory, and software development were compared to the practices of other affiliates and competitors. Unit costs were developed at a level far more detailed than the company normally tracked, and numerical measures of drivers that explained the structural and efficiency causes of variation in cost performance were identified. Potential costs savings of 10-50 percent were estimated, and procedures for better identification of inefficiencies were suggested.

- For an electric utility seeking to improve its plant maintenance program, Mr. Graves directed a study on the incremental value of a percentage point decrease in the expected forced outage rate at each plant owned and operated by the company. This defined an economic priority ladder for efforts to reduce outage that could be used in lieu of engineering standards for each plant's availability. The potential savings were compared to the costs of alternative schedules and contracting policies for preventive and reactive maintenance, in order to specify a cost reduction program.

- Mr. Graves conducted a study on the risk-adjusted discount rate appropriate to a publicly-owned electric utility's capacity planning. Since revenue requirements (the amounts being discounted) include operating costs in addition to capital recovery costs, the weighted average cost of capital for a comparable utility with traded securities may not be the correct rate for every alternative or scenario. The risks implicit in the utility's expansion alternatives were broken into component sources and phases, weighted, and compared to the risks of bonds and stocks to estimate project-specific discount rates and their probable bounds.

PROFESSIONAL AFFILIATIONS

- IEEE Power Engineering Society
- Mathematical Association of America
- American Finance Association
- International Association for Energy Economics

TESTIMONY

Rebuttal report on spent nuclear fuel removal on behalf of Yankee Atomic Electric Company, Connecticut Yankee Atomic Power Company, Maine Yankee Atomic Power Company before the United States Court of Federal Claims, Nos. 07-876C, No. 07-875C, No. 07-877C, August 5, 2011.

Direct Testimony on rehearing regarding the allowance of swaps in Rocky Mountain Power's fuel adjustment cost recovery mechanism, on behalf of Rocky Mountain Power before the Public Service Commission of the State of Utah, July 2011.

Comments and Reply Comments on capacity procurement and transmission planning on behalf of New Jersey Electric Distribution Companies before the State of New Jersey Board of Public Utilities in the Matter of the Board's Investigation of Capacity Procurement and Transmission Planning, NJ BPU Docket No. EO11050309, June 17, 2011; July 12, 2011.

Rebuttal testimony regarding Rocky Mountain Power's hedging practices on behalf of Rocky Mountain Power before the Public Service Commission of the State of Utah, Docket No. 10-035-124, June 2011.

Expert and Rebuttal reports regarding contract termination damages, on behalf of Hess Corporation before the United States District Court for the Northern District of New York, Case No. 5:10-cv-587 (NPM/GHL), April 29, 2011, May 13, 2011.

Expert and Rebuttal reports on spent fuel removal at Rancho Seco nuclear power plant, on behalf of Sacramento Municipal Utility District before the U.S. Court of Federal Claims, No. 09-587C, October 2010, July 1, 2011.

Rebuttal testimony on the Impacts of the Merger with First Energy on retail electric competition in Pennsylvania, on behalf of Allegheny Power before the Pennsylvania Public Utility Commission, Docket Numbers A-2010-2176520 and A-2010-2176732, September 13, 2010.

Expert and Rebuttal reports on the interpretation of pricing terms in a long term power purchase agreement, on behalf of Chambers Cogeneration Limited Partnership before the Superior Court of New Jersey, Docket No. L-329-08, August 23, 2010, September 21, 2010.

Expert and Rebuttal reports on spent fuel removal at Trojan nuclear facility, on behalf of Portland General Electric Company, The City of Eugene, Oregon, and PacifiCorp before the United States Court of Federal Claims No. 04-0009C, August 2010, June 29, 2011.

Rebuttal and Rejoinder testimonies on the approval of its Smart Meter Technology Procurement and Installation Plan before the Pennsylvania Public Utility Commission on behalf of West Penn Power Company d/b/a Allegheny Power, Docket Number M-2009-2123951, October 27, 2009, November 6, 2009.

Supplemental Direct testimony on the need for an energy cost adjustment mechanism in Utah to recover the costs of fuel and purchased power, on behalf of Rocky Mountain Power before the Public Service Commission of Utah, Docket No. 09-035-15, August 2009.

Expert and Rebuttal reports on spent nuclear fuel removal on behalf of Yankee Atomic Electric Company, Connecticut Yankee Atomic Power Company, Maine Yankee Atomic Power Company before the United States Court of Federal Claims, Nos. 98-126C, No. 98-154C, No. 98-474C, April 24, 2009, July 20, 2009.

Expert report in regard to opportunistic under-collateralization of affiliated trading companies, on behalf of BJ Energy, LLC, Franklin Power LLC, GLE Trading LLC, Ocean Power LLC, Pillar Fund LLC and Accord Energy, LLC before the United States District Court for the Eastern District of Pennsylvania, No. 09-CV-3649-NS, March 2009.

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