Large Filing Separator Sheet

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This will occur because excess capacity will suppress the market price of generation, affecting the market value of all generation assets, which will, in turn, affect all utilities' stranded costs.

Q. Will the move to competition affect any other cost elements on the utilities' books?

A. Yes, it will. Regulatory assets are an additional element of costs on the books that need to be recovered during the transition period. As I explained earlier, they reflect costs that have been paid by the utility and benefits that have been received by customers that, because of Commission policies or accounting requirements, have not been fully collected in rates.

Q. Some critics of stranded cost recovery argue that electric utilities should be denied recovery of stranded costs because firms in competitive markets typically cannot recover uneconomic investments. Do you agree with this view?

A. No, not as it relates to assets on the utilities' books or commitments made prior to the onset of competition. A regulated firm operates and invests under a different set of rules and constraints than does a competitive firm. Unlike a company in the free market, a regulated firm faces regulatory obligations as well as limits on both potential risk and potential return on its investments.

Under regulation, utilities such as AEP Ohio have been required to meet an obligation to supply power and energy to all customers who locate in their service areas. This obligation required long-lived investments to be made well in advance of actual growth in demand. These investments were subject to review by regulators for prudence and placed in rate base. Utilities were given an opportunity, but not a guarantee, to earn an allowed return on approved investments. The *quid pro quo* was the limitation of competitive entry that would allow the recovery of prudently incurred investments over their life. If the state alters the regulatory relationship, entry by other firms may result in market prices at which the utility will no longer be able to cover costs including return of and on past investments. More important, past regulation limited the potential return on regulated firms' investments. Investments made in new generating plants after the advent of competition will be subject to the same market discipline as in any other competitive business.

Q. Do incumbent obligations limit the extent to which utilities can reduce stranded costs or prepare for competition?

A. Yes, they do. In a competitive market, firms face constant pressure to operate efficiently and only engage in those activities in which they are low-cost producers (and consequently can sell at a profit). However, the existing regulatory paradigm imposes significant cost burdens on incumbent utilities. These include providing service to all customers in a given service territory, planning and investing to meet estimated future demand, and providing other non-market services. Many such obligations are unprofitable and would not be provided on the same basis in a competitive market. Incumbents are limited in the extent to which they can respond to anticipated changes in the marketplace as long as they continue to be obliged to provide these non-market services.

Q. What are your views on the argument that the incumbent utility should not be allowed to recover its stranded costs because it has already been compensated in rates for the risk of stranded costs?

A. I think that the argument is unfounded. Utility shareholders have not been compensated for the risk of stranded investments. For shareholders to have been compensated for such risk, one must assume that the Commission, through a general rate case or some other mechanism, increased rates sufficiently to enable existing investors to recoup their original investment and to receive a return on invested capital that is commensurate with the risk taken. Therefore, the Commission's ratemaking methodologies must be able to capture any changes in risk stemming from the introduction of competitive markets.

Q. Are the Commission's ratemaking methodologies able to capture any changes in risk stemming from the introduction of competitive markets?

A. No, they are not. Standard rate making procedures, such as those that use the discounted cash flow method to estimate the cost of equity, use industry-wide measures for comparison and do not incorporate company- or state-specific risk information. Furthermore, the techniques used by the Commission to determine the utility's authorized equity return would have measured the return required by a new investor, not the return required to compensate existing investors for stranded costs. These techniques measure required equity returns based on such market data as dividends, dividend growth, and stock price. While these techniques are capable of measuring the return that would be required to compensate the marginal investor for the added business risk associated with open access, they are incapable of measuring the additional return that would be required to compensate existing shareholders for stranded costs. That is, the techniques measure the increase in cost of capital because of the added risk from open access; but they do not measure the added return required to compensate existing investors for the loss in return, resulting from reduced stock price and dividends, they would experience in the absence of stranded cost recovery. Investors would have required explicit compensation for the realistic threat of having to write off large amounts of previously approved rate base. The effect of the threat of denial of stranded cost recovery would have been significant enough to be very evident.

2. Stranded Cost Recovery Will Hasten Transition to Competition

Q. Will allowing recovery of stranded cost hasten the transition to competition?

A. Yes, it will. Allowing recovery of stranded costs hastens the transition from a fully regulated regime to a more competitive environment by lowering legal barriers and allowing incumbent firms to cooperate actively in facilitating a rapid transition to competition. Failure to resolve the stranded cost issue will limit the ability of utilities to cooperate with a rapid movement toward competition. This will occur because of the utilities' fiduciary duties to protect the financial rights of stockholders and the utilities' concerns that incumbent disadvantages may greatly handicap their ability to succeed. In contrast, stranded cost recovery "settles up" the remaining costs associated with the regulatory period and allows all parties to focus on competition.

Q. Could the nature of the transition to competition affect the magnitude of stranded costs?

A. Yes, it certainly could. If the transition is not properly done, there is a real likelihood of additional stranded costs. Under regulation, an incumbent firm has an obligation to supply all customers and to supply other mandated programs (e.g., low-income and energy efficiency programs). If the transition to competition leaves the utility with the costs of providing expensive programs and services, but exposes to competition the most profitable businesses, then the utility will be hurt. Market entrants that can choose their customer base and service offerings will naturally choose only profitable areas of entry. Continuing the service obligations for incumbents, without properly providing for the collection of the costs thereof, can result in adverse selection, whereby profitable customers and services are drawn away by competitors, leaving the incumbent to provide uneconomical services to a high-cost customer base. A reasonable solution to this problem is to include the cost of social programs in a wires charge that is payable by all customers who take delivery service.

Q. Will stranded cost recovery afford incumbents an unfair competitive advantage?

A. No, it will not. It is often asserted that stranded cost recovery allows an incumbent with above-market costs to compete unfairly with potential or actual competitors because some of its costs are "subsidized" by stranded cost recovery. This erroneous assertion is based on the "sunk cost fallacy", which assumes that such costs will have an effect on the decision at hand. It is a fundamental truth of competitive markets that firms will make production decisions based on avoidable or marginal costs, not sunk or unavoidable costs. In fact, correctly designed and implemented stranded cost compensation will ensure that competition based on production costs alone can take place effectively.

3. Economic Efficiency

Q. Is the recovery of stranded costs supported by gains in economic efficiency?

A. Yes, it is. If incumbents are not fully compensated for their stranded costs, they may be faced with difficult pricing options. On the one hand they may price services at levels that allow full cost recovery. However, such pricing may create the opportunity for uneconomic bypass – less efficient competitors would be able to enter the market and take business from the incumbent with attendant losses in efficiency. On the other hand, the utility may price services at competitive levels (if they exceed marginal cost) and forgo recovery of some of the costs of existing investments.

Developing a method to ensure recovery of prudent costs, whether through a non-bypassable charge to all customers (as specified in §4928.37 (A)(1)(a) and (b) of Am. S. B. No. 3) or charging entrants a fee so that transition costs are shared equitably among competing utilities, will allow for a level playing field so that all firms may compete on the basis of production costs.

Q. Can you provide an example illustrating how uncompensated stranded costs can create an opportunity for uneconomic bypass to inefficient entrants?

A. Yes. Suppose the marginal cost of existing coal-fired generation is 2 cents per kWh for the incumbent. New, gas-fired merchant plants have a marginal cost of 4 cents per kWh. Assume further that there are unamortized incumbent burdens of

4 cents per kWh. The incumbent now faces a difficult decision. If the incumbent wishes to price efficiently to compete with new entrants it will set its price below 4 cents per kWh. This price, however, will not allow it to recover its total fixed costs of 6 cents per kWh (including the 4-cent burden), which will harm the incumbent's long-term ability to compete. If the incumbent sets its price to recover all costs, the entrant will be able to undercut the incumbent's total cost by 2 cents per kWh, even though the incumbent has a lower marginal generation cost than the entrant. This would be inefficient because more scarce resources are consumed if the entrant generates the electricity instead of the incumbent.

Q. Why is it important for generation companies to compete on the basis of relative production costs?

A. A fundamental tenet of economic efficiency is that the price of a good should reflect the relative value of the inputs used to produce it. Information on the value of inputs is transmitted through the market price, which in competitive markets is determined by the marginal cost of the last unit sold into the market. Denial of stranded cost recovery would force incumbent utilities to recover stranded costs through the prices of their goods and services. This will create a wedge between market prices and marginal cost, which may allow generation companies with higher marginal costs of production, but without a stranded cost burden, to enter the market. The entry of high-cost generation would result in a welfare loss to society—in other words, the total cost of providing electricity to everybody would be higher than necessary.

Q. What other inefficiencies are created by disallowance of stranded cost recovery?

A. Failure to allow the opportunity for stranded cost recovery will also create inefficiencies related to capital costs. Saddling incumbent firms with stranded costs creates financial weakness and increases the return that will be required by future investors, making it more costly for incumbents to maintain and modernize their facilities. High capital costs caused by regulatory uncertainty will also tend to raise costs for distribution and other services that remain regulated. This should be of particular concern to the Commission. Furthermore, a decision by the Commission disallowing stranded cost recovery would cause all firms, regulated and unregulated, to lose faith in state promises that affect their ability to conduct business. This would likely have a negative impact on the economic climate in Ohio by harming the state's reputation as a desirable place for business and industry to locate.

B. Settling Stranded Costs in the Transition to Competition

Q. How will utilities recover stranded costs in Ohio?

A. According to §4928.31 of Am. S. B. No. 3, any transition plan filed with the Commission may include: "...an application to receive transition revenues...." Such transition revenues consist of "... the allowable transition costs of the utility as such costs are determined by the Commission...." (§4928.34 (A)(12)). Regulatory assets will be considered a subset of total transition costs and separately identified by the Commission (§4928.39). Additionally, total electricity prices charged to the consumer will remain frozen at current prices while stranded costs are recovered. The transition charge, and other unbundled charges, will be designed such that "...the total of all unbundled components in the rate unbundling plan are capped and shall equal...the total of all rates and charges in effect under the applicable bundled schedule of the electric utility...including the transition charge (§4928.34 (A)(6))." Finally, a utility must offer its unbundled electric services to all consumers within its service territory (§4928.35 (C)).

Q. If stranded costs and regulatory assets are determined by settlement or contested proceedings, pursuant to §4928.39 and §4928.40 of Am. S. B. No. 3, what principles should apply?

A. First, the total amount of compensation due the utility for assets should equal the total that it would have otherwise recovered through regulated rates. Second, above- and below-market values of generation assets in a utility's portfolio should be netted. Third, regulatory assets should be fully recoverable. These are costs the regulators have already approved whose payment has been delayed at the request of the Commission. They are IOUs that should be paid in full regardless of the magnitude or direction of any stranded costs.

Q. Once stranded costs have been recovered and the Commission and the legislature have made the legal transition to a competitive market for generation, who should be responsible for the costs and entitled to the benefits of deregulated assets?

A. The stockholders should assume the risks and garner the rewards from any deregulated assets that the utility chose to own following the Market Development Period.

C. Stranded Benefits

Q. Do you believe that if a utility has stranded benefits they should be used as an offset to regulatory assets in the transition charge?

A. No, I do not. If the state chooses to change its regulatory relationship with utilities, it should not have a claim on market values in excess of book values. Buying a service does not convey an equity interest in the underlying assets. For example, a purchaser of insurance has a claim against the provider for compensation for insured events that occur while the policy is in force. However, if the insured drops the policy and the insurance company's contractual obligation ends, there is no right of the former policy holder to the value of assets of the company regardless of their market value. The contract ends when both parties have met their obligations under the agreement. There is no economic basis to claim against the appreciated value of the property. Therefore, there can be no positive ratepayer value to offset against other obligations to the utility such as those relating to regulatory assets.

D. Stranded Cost Recovery Mechanisms

Q. Do the rules, as established by §4928.39 and §4928.40 of Am. S. B. No. 3, that will guide the recovery of stranded costs in Ohio establish a fair and effective stranded cost recovery mechanism?

A. Yes, they do. Based on my understanding of the requirements of Ohio's legislation, I believe that it comports with three principles that are important for establishing a fair and effective stranded cost recovery mechanism:

1) The recovery mechanism provides for recovery of regulatory assets in full, regardless of the magnitude or direction of any stranded costs;

2) The recovery mechanism should not distort price signals; and

3) The recovery period should be as short as reasonably possible.

I already have discussed the importance of the first of these principles.

1. The Recovery Mechanism Should Not Distort Price Signals

Q. How should stranded costs be recovered?

A. Stranded costs should be recovered through a nondiscriminatory and non-bypassable fee or transition charge, as specified in §4928.37 (A)(1)(a) and (b) of Am. S. B. No. 3. From the standpoint of economic efficiency, it is not important whether the fee is formally charged to the retailer or to the consumer as long as no customer can avoid it by switching suppliers. In other words, the transition charge to recover stranded costs should be paid by everyone so that it has a neutral effect on the competitive market. The Ohio legislation's approach of implementing a rate freeze and a transition charge collected by the distribution utility meets these criteria. Stranded costs can be allocated across customer classes according to traditional ratemaking methods to establish the amount of the charge by class.

Q. How should the charge be collected?

A. The transition charge should be collected from customers in a manner that does not distort their selection of a generation service supplier.

2. The Recovery Period Should be as Short as Reasonably Possible

Q. Over what time period should the transition charge be collected?

A. There are tradeoffs between long and short recovery periods for any stranded costs. Longer periods allow lower current rates and may be needed to give utilities with large stranded costs the opportunity to recover them in full. On the other hand, the shorter the recovery period, the sooner the Commission can close the door on the past regulatory regime. Even though a properly designed transition charge will not distort the balance between competitors, competition as a whole will be hindered if delivered prices differ from market prices for a long period of time. Where stranded costs are not large, I believe that, on balance, a shorter time is preferable. If stranded costs are high and rates are frozen, a longer recovery period may be the only means of allowing full recovery.

In the Ohio legislation, the Market Development Period is scheduled to end December 31, 2005, but may end earlier if AEP Ohio satisfies certain conditions. However, the time period allowed for the recovery of regulatory assets may extend to December 31, 2010. Given the range of circumstances of Ohio utilities, this range of potential recovery periods is reasonable.

Q. Does a short stranded cost recovery period unfairly assess costs to customers now while providing most of the benefits of competition at the end of a multi-year transition process?

A. No, it does not. While it would be desirable to match costs closely with benefits over time, there are many circumstances in which this is impractical. The lack of a close match in the timing of costs and benefits is an invalid reason not to proceed with a project that has clear long-term benefits. The only economic issue that the difference in timing makes is whether the present value of the future benefits exceeds the current costs.

III. Methods to Estimate Changes in Plant Value Caused by the Transition to Competition

Q. What are the principal methods that have been proposed in other jurisdictions to estimate changes in plant value attributable to retail open access?

A. The methodology that has been most widely used, and which I believe to be appropriate, is a revenue-based approach. However, three other estimation techniques have also been proposed in various jurisdictions. The first is known as the "comparable transactions" approach. A second alternative would require divestiture or auction of incumbent generation assets. The third alternative would use futures prices to predict the future path of market clearing prices and, thereby, prospective plant values.

A. Revenue-Based Approach

Q. Please describe the revenue-based approach to estimating changes in plant value.

A. Under a revenue-based or lost revenue approach, changes in plant value attributable to retail open access are computed as the difference between net book value of assets and the present value of projected margins earned from those assets under market prices.[1] This method compensates the utility for the loss in

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[1] The use of net book value is consistent with a more general cash flow analysis: net book value will equal the net present value of cash flows under cost-of-service regulation if the allowed rate of return is used as the discount rate.

the value of its assets and for any cost increases caused by the transition to competition. The revenue effects of other changes in utility operations such as transition costs or purchased power contracts, if applicable, can also be computed in this manner.

Q. What are the advantages of a revenue-based method?

A. This method is able to account for the financial effect that every source of generation stranded costs has on the utility: physical assets, long-term contracts, and transition costs. For example, under cost-of-service regulation, a generating plant would be included in rate base, contributing to a portion of the utility's revenue requirement. Over the life of the plant, that revenue stream would allow the utility to recover the cost of the plant and earn a fair return on its investment. With the advent of competition, however, the revenue stream earned by that same plant will be determined in the marketplace instead of by the Commission. The difference between the net book value and the present value of the revenue stream with competition is the measure of stranded cost under the revenue-based method.

Q. Please describe what you believe is an appropriate implementation of the net lost revenue method for evaluating plant value.

A. Under an appropriate implementation of the net lost revenue method, changes in plant value attributable to retail open access would be computed as the difference between the predicted fixed cost recovery through continuing regulation and the predicted recovery through market-based prices. This method has the advantage of using market-based inputs without the substantial costs and disadvantages associated with alternative methods.

Q. Is the net lost revenue method reasonable?

A. Yes, it is. This method compensates the utility for the loss in the value of its assets and for any cost increases caused by the transition to competition. Projected net revenues are the only sound basis for estimating changes in plant cost recovery arising as a result of competition.

Q. Is there a drawback to the lost revenue method?

A. Yes, there is. The lost revenue method requires that we make assumptions about several aspects of the future market, including gas prices, the entry of new generation, and utilization rates, as well as assumptions about future environmental regulation and compliance costs.

B. Comparable Transactions

Q. Please describe the comparable transactions approach.

A. The comparable transactions approach uses data from actual sales of generation assets to determine the market value. Typically, this method compares unsold generation assets with "comparable" assets that have been sold, and then estimates the value of the unsold assets by assigning them the average value from these sales.

Q. What are the critical components of the comparable transactions approach?

A. To obtain reliable estimates of market value from transactions involving generation assets, we need accurate, thorough, and detailed information from a large sample of transactions. The data set must meet three minimum criteria if the resulting estimates are to be reliable. First, all observations must include accurate and precise price data for each generation unit sold. This means that the units must be sold on a "stand-alone" basis and not as a part of a bundled transaction involving multiple elements. Second, transactions must contain adequate information on asset characteristics affecting the value of the generation asset. If, for example, a data set of transactions tracks only the fuel type and the size of the power plant, we lack vital information on key factors such as availability and heat rate that will affect the transaction price. Third, the data set must contain enough transactions, with enough variation among the measurable and observable characteristics of the transactions, for us to quantify how the market price of generating assets changes with variation in these measurable characteristics. A large number of transactions will also prevent idiosyncratic or "outlying" observations from inaccurately driving the results obtained from using the data.

In addition to these three minimum criteria, in order for two assets to be classified as comparable, the assets must have a sufficient number of measurable characteristics in common. Which and how many characteristics they must share is obviously a subjective judgment. However, to consider an asset to be comparable to another simply because they are in the same geographic region or have roughly the same capacity or fuel type does not control properly for other characteristics that create significant variation in values and prices. If we are to rely on a simple average of sold asset prices to estimate the value of another asset, the assets must truly be comparable.

Q. What are the potential advantages of using a comparable transactions approach to value assets?

A. When properly employed, the comparable transactions approach can provide a reasonable estimate of the market value of these assets without having to make an actual sale. It has been used successfully in other circumstances, for example, in the appraisal of the value of residential or commercial property. The validity of these valuations, however, requires a great deal of information and the ability to control explicitly for differences between assets or transactions.

Q. Should the comparable transactions approach be used to value generation assets?

A. At this point, no. Generation plant sales have not produced the information necessary to support the use of the comparables approach. My staff has been tracking sales of generation plant for some time now, in connection with our ongoing interest in electric restructuring issues. Based on our rather extensive ongoing review of transactions, I conclude that there is an insufficient number of transactions to support a comparable transactions analysis for AEP Ohio. Furthermore, most transactions have been for bundled groups of assets, often combining fuel types, rather than for assets on a stand-alone basis. Other deals we have reviewed include considerations beyond a straight sale of assets. As a result, it is virtually impossible to attach a value to a particular plant characteristic or set of characteristics.

Without sufficient data, the analyst cannot properly control for factors affecting market value, determine whether or not assets are comparable, or have confidence in the validity of average values. Using a comparable transactions approach under these conditions can provide very biased and inaccurate results.

Q. How might the comparable transactions approach misprice a generation asset?

A. The fundamental problem is that the relevant economic features of the supposedly comparable asset do not, in fact, match the corresponding features of the asset being valued. There are a variety of features that need to be taken into account. These include readily observable issues, such as the geographic market in which the generation assets are located, or their fuel costs. There are other features that can be equally important that are more difficult to observe. These include issues such as the maintenance history of the plant. Some owners have maintained power plants to a very high standard while others have chosen to economize on maintenance. Therefore, assets of the same chronological age may have very different future lives. Such differences may not be readily detectable from simple statistics that are publicly available. Even more challenging is identifying the strategic plans of owners. Within their portfolio of plants, a plant may be more valuable under one strategy than in another strategy. There is no information available on these differences.

The limited number of observations that can be used for comparative purposes makes all of these problems more difficult. With a limited number of observations, there may be no truly comparable asset. If reliance is placed on a sample of transactions that is not really comparable, then the imputed prices would be incorrect.

Q. Are there additional problems with applying a comparable transactions approach to estimating the value of generation assets?

A. Yes, there are. The comparable transactions approach may include additional biases, as illustrated by recent sales of generation units. Many transactions involve "sell-back" contracts between the new owner and the seller, under which some of the plant's output is sold back to the buyer for a period of time. The terms of these contracts are not public knowledge, yet the value of the plant depends heavily upon the prices and quantities committed under the contracts. To use a real estate analogy, these sales are similar to selling an apartment building where tenants have leases at various rents for different periods of time. These leases strongly influence what the apartment building is worth. We cannot properly value such a building if we do not know the terms of the leases. Therefore, the sell-back contracts amount to unobservable characteristics of the transaction that prevent us from comparing one plant with another.

C. Divestiture

Q. Please describe the divestiture or auction approach.

A. Some jurisdictions, such as California, have, in effect, required the divestiture or auction of generating units. With divestiture, utilities recover the net difference between the sale price of the units and their book value as stranded cost. This method also has severe limitations.

Q. Please detail these limitations.

A. First, it is an exceedingly crude and draconian instrument for achieving a fairly limited objective. Requiring divestiture to determine value is like killing a fly with explosives. It may accomplish the purpose at the price of greater harm.

Divestiture pursuant to regulatory mandates preempts the management's decision-making process and limits utilities' options for development of and participation in competitive markets going forward. This is an unwarranted intrusion on the operation of competitive markets. Company planning should be permitted to proceed unencumbered in competitive markets so long as all legitimate regulatory concerns are satisfied. Divestiture is a particularly onerous requirement in the case of multi-state holding companies such as AEP.

Secondly, mandatory divestiture can create significant costs. There are substantial transaction costs associated with the sale of plants such as corporate taxes on gains, complexities in transferring interdependent fuel and other supply contracts, soliciting shareholder approvals, and obtaining the release of indentured property from bondholders. A forced auction during a limited period may result in an inefficient auction design or bad market timing which may distort participants' valuations of an asset, thereby reducing the efficiency of this market-based mechanism.

D. Futures and Forward Prices

Q. Please briefly describe what a forward contract is?

A. Forward contracts are contracts between two parties for specific delivery of electricity in the future under specified, generally non-standard conditions. While forward market trades can go out several years, most are relatively short term.

Q. Please briefly describe what a futures contract is?

A. A futures contract is a special type of forward contract. It is an agreement between a seller and a buyer of a commodity to transact in a standardized amount of the commodity at a specified location, at a time in the future but at a price that is determined today. For example, on December 16, 1999, the May, 2000 Cinergy futures contract for electricity traded at $29 per MWh. By "going long", or buying this contract, I would commit to pay $29 per MWh of electricity to the seller of this contract for every MWh of electricity specified in the contract. The seller of the contract will be required to deliver the contracted amount of electricity at the expiration of the contract in May. The spot price for electricity in the Cinergy market at the expiration of the contract in May will not affect the $29 per MWh that I contracted to pay the seller. In fact, the May spot price could differ significantly from the $29 per MWh price specified by the futures contract.

Q. What are the distinctions between futures prices and forecast prices?

A. Futures contracts and prices represent firm exchange-traded commitments between two parties to a price that will be paid for electricity that will be delivered in the future. Forecast prices, on the other hand, simply represent individual parties' expectations of what the future market price of electricity is likely to be. These expectations will probably vary from one market participant to another.

Q. Are futures prices a reliable guide to valuing, electric generation assets directly?

A. No, they are not. We should not rely on futures prices to value a generating asset directly. Electricity futures are a recent phenomenon. They generally are available only out two years, which is too short a period to evaluate generation plant economics. In order to assign value to a generating asset, we would need estimates of future electricity spot prices for the entire duration of the remaining useful life of that asset.

Q. In your opinion when can futures prices be used to value an asset?

A. Futures prices can be used in evaluating assets when they "span" the life of the asset or contract under analysis. Spanning means that liquid and robust futures contracts exist over the entire time horizon, not just its first few months or years. Extending a twenty-four month strip of futures prices to quantify twenty years of stranded costs, without appealing to or relying on any fundamental models or analyzing various possible market scenarios, is not a prudent approach.

Q. What do you conclude about the reliance on futures prices for the purpose of the estimation of future generation plant values?

A. Any substantial reliance on electricity futures prices to estimate the value of generation plant several years into the future is badly misplaced.

Q. Can forward prices for electricity be used to impute market value to generating plants?

A. No. Beyond the short term, there is not much liquidity for forward contracts in electricity and, as a result, little reliable price information. Moreover, because these contracts are not standardized, and exchange traded, they are not readily convertible into "market" prices

E. Revenue-Based Approach is Preferable

Q. Please explain why the revenue-based approach for calculating plant values under competition is preferable to other methods used for the purpose of computing stranded costs.

A. As Dr. Kahn discusses in detail in his testimony, the relationship between demand, plant costs, plant dispatch, and market prices is a systematic one. As a result, simulation models, which recreate the dynamics of the marketplace, can be used to estimate not only market prices, but also plant production levels and costs. Prices, production levels, and costs are direct inputs in a calculation of plant profitability over time that, in turn, can be utilized for asset valuation.

Because the revenue-based approach reflects all sources of stranded costs, it enables a comprehensive accounting of the financial effects on the utility. The lost revenue approach is also generally consistent with rate-of-return regulation. In the case of the other methods, each has very serious deficiencies in its application to AEP Ohio's assets. A "comparable transactions" approach would be complex, resource intensive, and likely inaccurate because of the limited availability of data on appropriate transactions. The second alternative, divestiture or auction of generating units, is unnecessarily intrusive to the operations of incumbent utilities, especially those that operate in more than one state or are members of multi-state holding companies. Furthermore, auction design, timing of the auction, and transaction costs may adversely affect the outcome of a divestiture alternative. The third alternative, futures or forward prices for electricity, at least at this point, uses unreliable predictors of the future value of generating assets because futures markets for electricity are not robust enough to provide sufficient guidance to market prices more than a year or two into the future.

IV. Implementation of a Revenue-Based Estimate of Stranded Cost

Q. What standards should be used to establish reliable stranded cost estimates?

A. In general, stranded cost estimates ought to be reproducible. Their calculation should use appropriate and verifiable methods and should clearly indicate assumptions so as to be reproducible by other, similarly skilled analysts.

Q. Have you estimated the value of plants serving AEP Ohio customers assuming competition begins on January 1, 2001?

A. Yes. I have estimates under two alternative scenarios.

Q. Why have you made alternative estimates?

A. There are significant variables that need to be forecasted to estimate the future prices for electricity and levels of production that underlie a revenue-based estimate of plant value. However, there is a significant degree of uncertainty in single point estimates of these variables. Therefore, I established alternative scenarios for the simulation of market conditions by Dr. Kahn that incorporate different combinations of plausible values for the variables.

Q. Please explain which variables are uncertain.

A. The future cost of fuel is a variable that is both fundamental to estimates and difficult to forecast with confidence. As Dr. Kahn explains, the most important fuel price for long-run market simulation purposes is the price of natural gas. The predictability of gas prices in the long run, however is limited. Historically, gas prices have shown substantial volatility over time, moving both much higher and much lower than consensus forecasts for sustained periods. Therefore, using a single gas price forecast creates potential that the actual outcome will be significantly above or below that forecast. Among credible forecasts of gas prices, the range of predicted prices can differ by as much as 25% over the relevant period. For the year 2010, for example, prices at the Henry Hub in Louisiana could be as low as $2.70 per MMbtu or as high as $3.40 per MMBtu.

Q. What other variable is fundamental to simulating future markets with values that are uncertain?

A. Future levels of environmental regulation also are important in Dr. Kahn's market simulations, but entail high levels of uncertainty. For example in 1997, EPA proposed additional NOx controls that may require substantial investments for plants using coal-fired technology, and increases in levels of the variable costs of compliance. The outcome of this proposal is in doubt. While the EPA has indicated that it remains committed to its proposed NOx program, the courts recently called this program into question. Moreover, affected states have expressed a variety of views on this issue. Thus, there is now political uncertainty about whether the proposed EPA program will be implemented in its current form and on its current schedule.

Additional environmental regulation is always possible and has been recently suggested. This would substantially affect generator costs. For example, the EPA is currently reviewing new source compliance by many existing coal-fired generating units that have undergone capital repairs. Other possibilities include further SO_2 regulation, carbon taxes, and controls on mercury.

Further, in the recent past, we have seen several new environmental restrictions on electricity generators proposed and implemented. There are several more regulations that have been currently proposed and are likely to be promulgated in the near future. The EPA, the state environmental agencies, and the federal and state legislatures have been extremely active in monitoring and restricting the operations of electricity generators. Further, the United States has signed on to international treaties such as the Kyoto Protocol, which, if ratified, will require federal agencies such as the EPA to achieve certain pre-specified emissions reductions targets. As a result, I believe that a more stringent environmental regime should be factored into any estimate of market values for AEP Ohio's generation assets.

Since there is general consensus on more stringent environmental regulation in the future, the greatest qualitative uncertainty in estimating the market value for AEP Ohio's generation assets relates to the direction of the future path of fuel prices. A more stringent environmental scenario will increase demand for natural gas to replace coal generation. Increased demand for gas is most consistent with the higher gas price case.

Dr. Kahn's simulations incorporate the variable costs of environmental controls into the calculation of market clearing prices (MCP) and production levels. Plant retirements for his simulations are affected by requirements for large-scale retrofitting of smaller generation units. His analysis, therefore, requires a judgement about the outcome of these controversies.

Q. Did you establish alternative scenarios to deal with the problem of gas price uncertainty?

A. Yes, I did. I identified two different gas price forecasts as representing a reasonable proxy for the forecast range of potential gas market conditions for our calculations. These forecasts are based on proprietary data that Cambridge Energy Research Associates (CERA) has made available to AEP Ohio. The higher of the two sets of CERA gas prices reflects a "gas favored scenario" (the CERA Gas-Favored Prices), while the lower represents a gas commodity forecast (the CERA Gas Commodity Prices). The CERA gas forecast range provides a reasonable proxy for the current range of available forecasts.

Q. Did you establish alternative scenarios to deal with uncertainty regarding environmental regulations?

A. Yes, I did. I assume two environmental scenarios. Under my base case scenario, I have assumed only the continuation of the CAA Title IV SO_2 allowance program and implementation of NOx controls by 2003. As I mentioned above, there is currently some legal uncertainty surrounding the proposed EPA NOx plan; I assume that it will be resolved and that a modified version of the proposal will be implemented that includes 65 % NOx reduction in the Midwest and 85% reduction in the Northeast.

A second, alternative environmental scenario simulates the effects of more stringent environmental standards based on possible future regulations discussed in Company Witness McManus's testimony. This case assumes year-around NOx reductions, with universal selective catalytic reduction (SCR) and scrubber installation.

Q. How did you link your alternative fuel and environmental scenarios together?

A. I concluded that the likely changes in fuel mix consistent with the more stringent alternative environmental scenario are less consistent with low gas prices. Dr. Kahn's scenarios demonstrate that there is much greater use of gas under the alternative environmental scenario. Therefore, my alternative environmental scenario is combined with the higher gas price case. Conversely, I concluded that the base case environmental scenario was less consistent with high gas prices. My base case environmental scenario is, therefore, combined with the low gas price case. Using these alternative assumptions, I arrive at two estimates of plant values and associated levels of stranded costs.

V. *Results of Revenue-Based Estimates of Plant Value Changes*

A. Implementation of a Revenue-Based Estimate of Plant Value Changes

Q. Please outline your method for estimating the value, following introduction of competition, of the generating plant serving AEP Ohio customers.

A. I estimate the value of AEP Ohio's generation plants under competitive conditions by comparing the book values of these plants to values that a competitive market for electricity would assign to them. As I have indicated above, I believe that the only reliable method of estimating market values for AEP Ohio's generation plants is a revenue-based method. Implementing this method and obtaining estimates of market values for AEP Ohio's generation plants entails the following three steps. In the first step, Dr. Kahn has utilized a production costing model to simulate the dynamics of a competitive electricity market for the years 2000, 2003, 2005, 2010, and 2015. The model's output provides estimates of market prices for electricity and plant-specific levels of electricity generation, variable operations and maintenance expense (excluding fuel costs), fuel expense, and plant emissions. I interpolate between observed values for the years simulated by Dr. Kahn to fill in for the intervening years and use these projections to compute estimates of revenues that will be generated by AEP Ohio in a competitive electricity market,

The second step in the exercise, imputing a market value to AEP Ohio's generation plants, involves estimating future cash flows that are attributable to these assets. To calculate these cash flows for the specified years, I begin with my estimates of gross revenues and subtract administrative and general expenses (A&G), property and revenue taxes, and income taxes. I also estimate and deduct environmental expenses (principally SO_2 allowance costs) based upon the plant emissions levels supplied to me by Dr. Kahn.

The final step in estimating market values for AEP Ohio's generation plants involves discounting the projected future cash flows using discount rates appropriate for unregulated electricity generation companies in order to arrive at a net present value (NPV) figure. This NPV of projected future cash flows generated by AEP Ohio's plants provides an estimate of their respective market values. A company-specific comparison of these estimated market values with the book values of each company's generation plants gives us an estimate of stranded costs.

Q. *Please explain how you selected the discount rates that you use to compute the NPV of the cash flows.*

A. The discount rates in this calculation represent the respective assumed weighted average costs of capital for each of the two companies. Each company's unregulated generation subsidiary was assumed to have a capital structure consisting of 40% debit, 60% equity. Each company's weighted average cost of capital is derived by the sum of the cost of equity capital weighted by the proportion of equity in its capital structure and its cost of debt financing weighted by the proportion of debt in its capital structure. The cost of equity capital that I use in this calculation is one derived for a stand-alone generating company. The cost of debt capital that I use is each of the two companies' actual costs of debt as supplied to me by AEP Ohio.

Q. For stranded cost determination, is it necessary to develop revenue and expense estimates for the years following 2015?

A. Yes. However, I need to balance the desirability of having long-term revenue estimates against the increasing effect of uncertainty on the accuracy of my estimates over time. Over such a long time period, technological change, environmental regulations, and social and economic conditions can have a profound effect on market conditions. If I were to assert that I was able to forecast these conditions accurately for the period out to 2020 or beyond, the claim would not be credible.

The margins on AEP Ohio plants likely will deteriorate in the years following 2015. I assume that the cash flows observed in 2015 decay at a constant rate to zero by 2030. I use this cash flow pattern to estimate NPV of AEP Ohio plants for the period 2015 to 2030.

B. Description of Results

Q. Please summarize the steps you have taken to estimate changes in the value of AEP Ohio's generation plant.

A. As I explained earlier, upon receiving estimates of market prices, production levels, operating costs and emissions for each of the scenarios that Dr. Kahn has simulated, I interpolate between his estimates to establish annual values for each of the variables under each scenario.

Next, I convert these market revenues to cash flows available to owners after deducting non-production expenses and income taxes. In addition to incorporating the costs of SO_2 allowances into the cash flow calculation, an adjustment is required to deal with the NOx mitigation plan investments. These investments will occur, for the Base Environmental Case, in the years 2001 to 2005 and must be discounted back to the beginning of 2001, and for the Alternative Environmental Case, in the years 2006 to 2010 and must be discounted back to the beginning of 2001, to make the appropriate comparison.

Q. Do you make any other adjustments for environmental costs?

A. Yes, I do. While I calculate the costs of emissions allowances for both SO_2 and NOx under the base environmental case, I believe that the allowance market will cease to exist under the alternative environmental case. I therefore do not make an adjustment for the purchase of allowances in the alternative environmental case but assume that compliance will be achieved through installation of control technologies.

Q. Please describe your estimate of stranded generation costs for AEP Ohio.

A. The following table summarizes my results. EXHIBIT NO. __JHL-2 contains the details behind these numbers.

Stranded Cost ($ millions)

	CSP		OPCO	
	Low Gas	High Gas	Low Gas	High Gas
MPV of Cash Flow 2001-2015	377.5	400.5	966.8	954.7
MPV of Cash Flow 2016-2030	79.2	97.1	203.2	308.8
	456.7	497.6	1,170.0	1,263.5
Book Value (12/31/2000)	974.3	974.3	1,309.4	1,309.4
Net Stranded Cost	517.6	476.7	139.4	45.9

Q. Can you summarize your conclusions regarding generation-related stranded costs?

A. Yes. I have concluded that:

1) The only valid method of estimating the value of AEP Ohio's generating plant is based on projected net revenues. The comparable sale approach is not reliable because of inadequate sales data, small sample size, and unique characteristics of plants, related contracts, and specific locations. Forward electricity prices offer an inadequate basis for estimates of future market prices.

2) The possible market values for AEP Ohio's generation assets, less their respective book values, in current dollars and on a present value basis, can be summarized by company. For OPCO, the stranded costs range from $45,889,000 to $139,350,000. For CSP, the stranded costs range from $476,698,000 to $517,578,000.

VI. Summary and Conclusions

Q. What are your conclusions?

A. There are compelling reasons to allow electric utilities the opportunity to recover potentially stranded costs as part of the movement to replace regulation with competition in Ohio. The production assets that are above-market in value should be netted against those below market in determining each utility's stranded generation costs. If the net value of utility assets in a competitive market exceeds book value, the premium values belong to the stockholders. In any event, the utility should recover the value of regulatory assets from which ratepayers have already benefited.

The best means of determining stranded costs is through a comparison of revenues the utility is likely to obtain in a competitive market with those they would obtain under regulation. This method requires modeling the results of a competitive market. This modeling requires assumptions regarding fuel prices, environmental requirements, the pattern of market entry, how markets are organized, how transmission is priced and allocated, and how various obligations on the AEP System should be treated.

Q. Does this conclude your testimony?

A. Yes, it does.

JOHN H. LANDON

John Landon specializes in the application of economic and statistical principles to firms, industries and markets. His work has spanned many industries including electric and gas utilities, computer equipment, computer software, pharmaceuticals, hospitals, medical implants, publishing, transportation, and manufacturing. He has provided reports and testimony on issues including mergers, antitrust actions, contract disputes, regulatory rule determinations, and labor market disputes.

Dr. Landon has testified more than 100 times before federal district courts, state courts, the Securities and Exchange Commission, the Federal Energy Regulatory Commission, and various state commissions, and has prepared numerous expert reports and affidavits. He has authored or co-authored more than 20 articles published in academic and trade journals, two book chapters, and several monographs. His research areas include electric utilities, labor markets, vertical integration, and technological change.

Prior to joining Analysis Group Economics, Dr. Landon was Senior Vice President at NERA, Inc. Previously, he held positions as Associate Professor of Economics at the University of Delaware and Case Western Reserve University. Dr. Landon holds a Ph.D. in Economics from Cornell University.

PROFESSIONAL ACTIVITIES

Member of the Governor of Delaware's Economic Advisory Committee

Director of the Center for Policy Studies at the University of Delaware

A Director of the Delaware Econometric Model Group

Senior Research Associate in the Research Program in Industrial Economics at Case Western Reserve University

Member of the American Economic Association

Associate Member of the American Bar Association

TESTIMONY PROVIDED FOR THE FOLLOWING CLIENTS:

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Appalachian Power Company
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Projected Generation Related Net Stranded Costs
Columbus and Southern Company
Low Gas + Base Environment

Stranded Cost Calculation Summary	
NPV of Cash Flow 2001 - 2015	$377,541
NPV of Cash Flow 2016 - 2030	$79,210
Total NPV Cash Flow	$456,751
Base	$974,329
Net Stranded Costs	$517,578

Income Statement		Source	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	Present Value @ 10.79%
Revenues																			
1) Total GWH Generation		Input	16,230	16,300	16,360	16,451	16,541	16,631	16,403	16,179	15,957	15,739	15,524	15,092	14,672	14,264	13,868	13,442	
2) AEP Price		Input	$23.52	$23.76	$24.01	$24.26	$25.53	$26.79	$27.58	$28.39	$29.22	$30.06	$30.96	$31.81	$32.69	$33.60	$34.53	$35.48	
3) Total Revenues			$396,780	$404,536	$412,448	$420,512	$445,283	$470,053	$478,063	$486,261	$494,558	$503,006	$511,600	$511,972	$512,346	$512,719	$513,093	$513,467	
Expenses																			
4) Production Expense excl fuel		Input	$59,059	$61,133	$63,279	$65,501	$68,788	$72,030	$74,846	$77,772	$80,812	$83,971	$87,254	$87,107	$86,961	$86,815	$86,669	$86,523	$538,574
5) Fuel Expense		Input	$179,810	$180,578	$181,249	$181,921	$186,411	$190,901	$194,246	$197,848	$201,110	$204,633	$208,218	$204,507	$200,863	$197,283	$193,767	$190,314	$1,383,673
6) Decommissioning/Dismantling		Input	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$17,853	$18,402	$0	$3,726	$10,920
7) SO2 allowance costs		Input	$11,627	$15,798	$18,967	$18,219	$19,843	$21,168	$18,248	$16,388	$12,812	$8,879	$8,208	$6,468	$4,869	$2,866	$998	$0	$101,516
8) A&G Expense		Input	$61,881	$68,843	$65,998	$68,905	$70,470	$73,034	$71,390	$75,886	$82,786	$76,890	$76,724	$77,874	$79,043	$80,228	$81,432	$82,653	$532,835
9) Depreciation - Steam Gen	3.20%	Calculated	$49,884	$51,000	$52,718	$54,965	$56,477	$57,241	$58,026	$58,828	$59,862	$60,498	$61,261	$62,176	$62,771	$63,383	$64,176	$64,942	
10) - Hydro		Calculated	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
11) Retirements			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$10,999	$0	$0	$1,829	
12) Taxes - NOx and Scrubber	0.15%	Calculated	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
13) Taxes Other - Other		Input	$41,108	$42,707	$13,863	$14,163	$14,679	$15,216	$15,774	$16,351	$16,950	$17,573	$18,218	$18,885	$19,576	$20,293	$21,035	$21,805	$143,429
14) Total Expenses		Calculated	$403,489	$418,058	$393,873	$404,875	$416,446	$429,591	$432,528	$441,686	$453,922	$452,142	$459,881	$457,020	$482,865	$469,270	$448,075	$451,792	$3,142,713
15) Operating Income		Calculated	($6,709)	($13,520)	$18,575	$15,637	$28,837	$40,462	$45,555	$44,585	$40,636	$50,864	$51,619	$54,952	$29,481	$43,449	$65,018	$61,674	$227,824
16) Interest Expense	7.90%	Calculated	$31,504	$30,810	$30,863	$31,380	$31,105	$30,050	$28,969	$27,823	$26,851	$25,773	$24,688	$23,530	$22,084	$20,637	$19,390	$18,085	$203,058
17) Income Before Taxes		Calculated	($38,193)	($44,330)	($12,288)	($15,542)	($2,268)	$10,412	$16,586	$16,861	$13,784	$25,091	$26,930	$31,423	$7,407	$22,811	$45,628	$43,590	$24,766
18) Schedule M		Input	($2,886)	($463)	($463)	($463)	($463)	($463)	($463)	($463)	($463)	($463)	($463)	($463)	($463)	($463)	($463)	($463)	($3,370)
19) Taxable Income		Calculated	($41,079)	($44,793)	($12,751)	($16,006)	($2,731)	$9,949	$16,103	$16,198	$13,321	$24,628	$26,467	$30,960	$6,944	$22,348	$45,165	$43,127	$21,396
20) Current Fed/State Tax	40.56%	Calculated	($16,662)	($18,168)	($5,172)	($6,492)	($1,108)	$4,036	$6,531	$6,570	$5,403	$9,989	$10,736	$12,557	$2,817	$9,064	$18,319	$17,492	$8,678
21) Deferred FIT/ITC	35.00%	Input	$1,010	$182	$182	$182	$182	$182	$182	$182	$182	$182	$182	$182	$182	$182	$182	$182	
22) Total Income Taxes		Calculated	($15,651)	($18,008)	($5,010)	($6,330)	($946)	$4,198	$6,683	$6,732	$5,565	$10,151	$10,897	$12,719	$2,978	$9,226	$18,481	$17,654	$9,858
23) Net Income Before Preferred		Calculated	($22,541)	($26,324)	($7,278)	($9,213)	($1,322)	$6,215	$9,873	$9,929	$8,219	$14,940	$16,033	$18,703	$4,429	$13,585	$27,147	$25,936	$14,909
Cash Flow																			
24) Net Income Before Preferred		From above	($22,541)	($26,324)	($7,278)	($9,213)	($1,322)	$6,215	$9,873	$9,929	$8,219	$14,940	$16,033	$18,703	$4,429	$13,585	$27,147	$25,936	$14,909
25) Plus Interest Expense		From above	$31,504	$30,810	$30,863	$31,380	$31,105	$30,050	$28,969	$27,823	$26,851	$25,773	$24,688	$23,530	$22,084	$20,637	$19,390	$18,085	$203,058
26) Plus Deferred Taxes		From above	$1,010	$182	$182	$182	$182	$182	$182	$182	$182	$182	$182	$182	$182	$182	$182	$182	
27) Plus Depreciation		From above	$49,884	$51,000	$52,718	$54,965	$56,477	$57,241	$58,026	$58,828	$59,862	$60,498	$61,261	$62,176	$62,771	$63,383	$64,176	$64,942	
28) Plus Retirements		From above	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$10,999	$0	$0	$1,829	
29) Less Construction		External File	$31,943	$37,795	$26,332	$38,503	$23,598	$24,168	$24,783	$25,413	$26,048	$26,690	$27,367	$23,723	$24,316	$24,924	$24,579	$25,193	$203,698
30) Less NOx (SNCR)		External File	$0	$0	$44,239	$32,390	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$69,873
31) Less NOx (SCR) and Scrubber		External File	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
32) Total		Calculated	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	$377,541
Capitalization																			
33) Debt		Input	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	
34) Equity		Input	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	
Investment																			
35) Gross Plant in Service - Steam Gen		Input	$1,574,841	$1,612,636	$1,682,209	$1,753,102	$1,776,700	$1,800,888	$1,825,681	$1,851,094	$1,877,142	$1,903,842	$1,931,208	$1,954,931	$1,968,248	$1,993,172	$2,017,750	$2,041,114	
36) - Hydro		Input	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
37) Accum. Depreciation - Steam Gen		Calculated	$629,812	$680,812	$733,529	$788,494	$844,971	$902,212	$960,238	$1,019,066	$1,078,718	$1,139,214	$1,200,574	$1,262,753	$1,325,523	$1,388,906	$1,453,081	$1,518,023	
38) - Hydro		Input	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
39) Net Plant		Calculated	$945,029	$931,826	$948,680	$964,608	$931,729	$898,676	$865,444	$832,028	$798,425	$764,628	$730,634	$692,179	$642,725	$604,266	$564,669	$523,091	
40) Plus Fuel Inventory		Input	$22,140	$22,140	$22,140	$22,140	$22,140	$22,140	$22,140	$22,140	$22,140	$22,140	$22,140	$22,140	$19,532	$19,532	$19,532	$19,057	
41) Plus M&S & Prepayments		Input	$18,000	$18,000	$18,000	$18,000	$18,000	$18,000	$18,000	$18,000	$18,000	$18,000	$18,000	$18,000	$18,000	$18,000	$18,000	$18,000	
42) Less Accum DFIT		Calculated	$10,840	$11,002	$11,164	$11,326	$11,488	$11,650	$11,812	$11,974	$12,136	$12,298	$12,461	$12,623	$12,785	$12,947	$13,109	$13,271	
43) Net Investment		Calculated	$974,329	$960,964	$977,656	$993,422	$960,381	$927,166	$893,772	$860,194	$826,428	$792,470	$758,314	$719,696	$667,472	$628,851	$589,093	$546,876	
44) Net Investment		Calculated	$974,329																

45) NPV of Cash Flow 2016 - 2030 $79,210

Projected Generation Related Net Stranded Costs
Ohio Power Company
Low Gas + Base Environment

Stranded Cost Calculation Summary	
NPV of Cash Flow 2001 - 2015	$968,821
NPV of Cash Flow 2016 - 2030	$203,210
Total NPV Cash Flow	$1,170,032
Base	$1,309,382
Net Stranded Costs	$138,350

Income Statement		Source	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	Present Value @ 10.47%
Revenues																			
1) Total GWH Generation		Input	48,624	48,812	49,001	49,190	49,857	50,085	48,162	46,316	44,536	42,830	41,187	40,919	40,651	40,386	40,122	39,860	
2) AEP Price		Input	$23.52	$23.76	$24.01	$24.26	$25.53	$26.79	$27.58	$28.39	$29.22	$30.08	$30.96	$31.81	$32.68	$33.60	$34.53	$35.48	
3) Total Revenues			$1,228,139	$1,246,894	$1,265,936	$1,286,269	$1,368,880	$1,462,091	$1,438,367	$1,424,772	$1,411,307	$1,397,988	$1,364,756	$1,409,979	$1,435,652	$1,461,812	$1,488,439	$1,515,560	
Expenses																			
4) Production Expense excl fuel		Input	$246,453	$266,161	$265,294	$275,808	$289,321	$302,833	$306,582	$310,378	$314,218	$318,107	$322,045	$334,496	$347,432	$360,867	$374,821	$389,315	$2,241,413
5) Fuel Expense		Input	$643,828	$615,424	$588,183	$562,149	$578,634	$591,119	$583,078	$575,142	$567,317	$559,598	$551,984	$555,312	$558,661	$562,029	$565,418	$568,827	$4,274,786
6) Decommissioning/Dismantling		Input	$0	$0	$0	$0	$0	$0	$0	$0	$34,860	$35,731	$24,401	$25,011	$0	$0	$0	$0	
7) SO2 allowance costs		Input	$0	$21,796	$28,984	$26,468	$25,984	$25,326	$18,675	$12,009	$5,308	$0	$0	$0	$0	$0	$0	$0	$114,873
8) A&G Expense		Input	$93,279	$94,870	$101,464	$102,737	$103,706	$104,863	$105,907	$106,827	$108,064	$109,114	$110,205	$111,307	$112,420	$113,544	$114,680	$116,826	$790,750
9) Depreciation - Steam Gen	3.40%	Calculated	$90,998	$97,185	$106,150	$109,772	$112,886	$116,087	$119,423	$122,459	$124,279	$126,107	$128,629	$131,222	$134,291	$137,254	$140,363	$143,590	
10) - Hydro	2.70%	Calculated	$2,959	$2,956	$2,956	$2,956	$2,956	$2,956	$2,956	$2,956	$2,956	$2,956	$2,956	$2,956	$2,956	$2,956	$2,955	$2,956	
11) Retirements			$0	$0	$0	$0	$0	$0	$0	$0	$58,750	$0	$18,413	$0	$0	$0	$0	$0	
12) Taxes - NOx and Scrubber	0.15%	Calculated	$0	$41	$71	$80	$86	$103	$103	$103	$103	$103	$103	$105	$103	$103	$103	$103	$680
13) Taxes Other - Other		Input	$78,147	$78,829	$42,536	$42,851	$43,172	$43,500	$43,835	$44,177	$44,527	$44,884	$45,248	$45,620	$46,000	$46,387	$46,783	$47,186	$358,576
14) Total Expenses		Calculated	$1,154,761	$1,166,082	$1,134,737	$1,122,819	$1,154,517	$1,186,737	$1,180,556	$1,173,849	$1,260,385	$1,196,600	$1,203,984	$1,206,029	$1,201,772	$1,223,140	$1,245,143	$1,267,803	$8,746,404
15) Operating Income		Calculated	$73,378	$80,832	$131,199	$162,448	$214,163	$265,354	$257,810	$250,923	$150,923	$201,368	$180,772	$203,950	$233,880	$238,672	$243,296	$247,747	$1,410,528
16) Interest Expense	7.18%	Calculated	$38,150	$39,992	$43,780	$44,549	$43,749	$43,312	$42,889	$41,730	$39,493	$37,211	$35,601	$33,977	$32,631	$31,262	$29,868	$28,450	$294,849
17) Income Before Taxes		Calculated	$35,228	$40,840	$87,419	$117,901	$170,414	$222,042	$215,121	$209,193	$111,430	$164,157	$145,171	$169,973	$201,259	$207,410	$213,428	$219,297	$1,115,679
18) Schedule M		Input	$3,466	$3,466	$3,466	$3,466	$3,466	$3,466	$3,466	$3,466	$3,466	$3,466	$3,466	$3,466	$3,466	$3,466	$3,466	$3,466	$25,670
19) Taxable Income		Calculated	$38,694	$44,306	$90,885	$121,367	$173,880	$225,508	$218,587	$212,659	$114,896	$167,623	$148,637	$173,439	$204,724	$210,876	$216,894	$222,763	$1,141,349
20) Current Fed/State Tax	40.68%	Calculated	$15,694	$17,971	$36,863	$49,226	$70,526	$91,466	$88,659	$86,256	$46,602	$67,988	$60,287	$70,347	$83,036	$85,531	$87,972	$90,353	$462,931
21) Deferred FIT/ITC	35.00%	Input	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	
22) Total Income Taxes		Calculated	$14,481	$16,757	$35,650	$48,013	$69,313	$90,253	$87,446	$85,041	$45,389	$66,775	$59,074	$69,134	$81,823	$84,318	$86,759	$89,140	$453,947
23) Net Income Before Preferred		Calculated	$20,747	$24,083	$51,769	$69,888	$101,101	$131,789	$127,675	$124,152	$66,041	$97,382	$86,097	$100,839	$119,435	$123,092	$126,669	$130,156	$661,732
Cash Flow																			
24) Net Income Before Preferred		From above	$20,747	$24,083	$51,769	$69,888	$101,101	$131,789	$127,675	$124,152	$66,041	$97,382	$86,097	$100,839	$119,435	$123,092	$126,669	$130,156	$661,732
25) Plus Interest Expense		From above	$38,150	$39,992	$43,780	$44,549	$43,749	$43,312	$42,889	$41,730	$39,493	$37,211	$35,601	$33,977	$32,631	$31,262	$29,868	$28,450	$294,849
26) Plus Deferred Taxes		From above	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	
27) Plus Depreciation		From above	$93,957	$100,121	$109,105	$112,727	$115,821	$119,053	$122,378	$125,414	$127,235	$129,063	$131,585	$134,177	$137,156	$140,209	$143,338	$146,546	
28) Plus Retirements		From above	$0	$0	$0	$0	$0	$0	$0	$0	$58,750	$0	$18,413	$0	$0	$0	$0	$0	
29) Less Construction			$97,736	$102,568	$90,117	$57,163	$92,019	$84,318	$98,677	$81,891	$83,930	$82,352	$84,411	$98,521	$88,984	$90,901	$93,174	$95,503	$641,906
30) Less NOx (SNCR)		External File	$0	$182,512	$124,435	$10,173	$10,962	$4,836	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$241,454
31) Less NOx (SCR) and Scrubber			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
32) Total		Calculated	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	$968,821
Capitalization																			
33) Debt		Input	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	
34) Equity		Input	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	
Investment																			
35) Gross Plant in Service - Steam Gen		Input	$2,725,298	$2,900,364	$3,194,916	$3,282,272	$3,365,152	$3,464,118	$3,560,798	$3,642,879	$3,667,880	$3,750,219	$3,818,217	$3,902,738	$3,991,422	$4,082,323	$4,175,498	$4,270,999	
36) - Hydro		Input	$109,453	$109,453	$109,453	$109,453	$109,453	$109,453	$109,453	$109,453	$109,453	$109,453	$109,453	$109,453	$109,453	$109,453	$109,453	$109,453	
37) Accum. Depreciation - Steam Gen		Calculated	1,587,274	$1,684,440	$1,789,590	$1,899,362	$2,012,028	$2,128,128	$2,247,549	$2,370,008	$2,494,287	$2,620,395	$2,749,024	$2,880,246	$3,014,447	$3,151,701	$3,292,064	$3,435,674	
38) - Hydro		Input	$44,176	$47,131	$50,086	$53,042	$55,997	$58,952	$61,907	$64,863	$67,818	$70,773	$73,728	$76,684	$79,639	$82,594	$85,549	$88,504	
39) Net Plant		Calculated	$1,203,299	$1,308,246	$1,464,692	$1,419,321	$1,406,580	$1,386,485	$1,360,784	$1,317,261	$1,215,216	$1,168,505	$1,102,918	$1,055,261	$1,006,789	$957,481	$907,318	$856,274	
40) Plus Fuel Inventory		Input	$92,929	$92,929	$92,929	$92,929	$92,929	$92,929	$92,929	$92,929	$80,308	$80,308	$78,043	$78,043	$78,043	$78,043	$78,043	$78,043	
41) Plus M&S & Prepayments		Input	$38,000	$38,000	$38,000	$38,000	$38,000	$38,000	$38,000	$38,000	$38,000	$38,000	$38,000	$38,000	$38,000	$38,000	$38,000	$38,000	
42) Less Accum DFIT		Calculated	$24,838	$23,623	$22,410	$21,197	$19,984	$18,771	$17,558	$16,346	$15,132	$13,919	$12,706	$11,492	$10,279	$9,066	$7,853	$6,640	
43) Net Investment		Calculated	$1,309,382	$1,475,551	$1,573,211	$1,529,053	$1,517,526	$1,496,644	$1,474,156	$1,431,846	$1,318,391	$1,272,894	$1,206,255	$1,159,812	$1,112,553	$1,064,458	$1,015,507	$965,677	
44) Net Investment		Calculated	$1,309,382																

45) NPV of Cash Flow 2016 - 2030 $203,210

EXHIBIT NO. __ JHL-2
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Projected Generation Related Net Stranded Costs
Columbus and Southern Company
High Gas + Alternative Environment

Stranded Cost Calculation Summary	
NPV of Cash Flow 2001 - 2015	$400,516
NPV of Cash Flow 2016 - 2030	$97,115
Total NPV Cash Flow	$497,631
Base	$974,329
Net Stranded Costs	$476,698

Income Statement		Source	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	Present Value @ 10.78%
Revenues																			
1) Total GWH Generation		Input	16,236	16,400	16,564	16,730	16,893	17,058	16,739	16,427	16,121	15,821	15,526	15,326	15,132	14,939	14,748	14,580	
2) AEP Price		Input	$23.52	$24.64	$25.81	$27.04	$28.64	$30.23	$30.83	$31.44	$32.06	$32.70	$33.34	$34.34	$35.36	$36.41	$37.49	$38.60	
3) Total Revenues			$396,780	$421,730	$448,249	$476,435	$507,138	$537,841	$537,082	$536,324	$535,568	$534,812	$534,057	$541,583	$549,214	$556,953	$564,801	$572,760	
Expenses																			
4) Production Expense excl fuel		Input	$59,050	$61,292	$63,610	$66,016	$69,463	$72,911	$78,075	$83,606	$89,527	$95,866	$102,656	$106,224	$107,854	$110,550	$113,313	$116,146	$590,050
5) Fuel Expense		Input	$179,910	$181,510	$183,124	$184,763	$190,264	$195,778	$196,682	$197,613	$198,639	$199,468	$200,402	$200,756	$201,110	$201,465	$201,821	$202,177	$1,403,352
6) Decommissioning/Dismantling		Input	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$17,963	$18,492	$0	$3,726	
7) SO2 allowance costs		Input	$0	$14,121	$17,383	$5,083	$20,880	$7,319	$18,558	$14,880	$11,010	$7,523	$0	$0	$0	$0	$0	$0	$73,802
8) A&G Expense		Input	$61,881	$65,843	$65,996	$69,905	$70,470	$73,034	$71,280	$75,866	$92,786	$76,580	$76,724	$77,874	$79,043	$80,228	$81,432	$82,653	$532,836
9) Depreciation - Steam Gen	3.20%	Calculated	$49,884	$51,000	$52,718	$54,965	$56,477	$57,241	$59,187	$62,342	$65,576	$68,880	$72,288	$74,367	$74,980	$76,592	$78,364	$77,151	
10) - Hydro		Calculated	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
11) Retirements			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$10,999	$0	$0	$1,829	
12) Taxes - NOx and Scrubber	0.15%	Calculated	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
13) Taxes Other - Other		Input	$41,106	$42,707	$13,863	$14,163	$14,679	$15,216	$15,774	$16,351	$18,950	$17,573	$18,218	$18,886	$19,576	$20,293	$21,035	$21,805	$143,429
14) Total Expenses		Calculated	$391,843	$417,472	$396,476	$394,865	$422,044	$421,497	$439,676	$450,259	$464,387	$464,912	$470,290	$477,127	$511,518	$506,530	$493,985	$505,486	$3,204,887
15) Operating Income		Calculated	$4,938	$4,258	$51,772	$81,570	$85,094	$116,343	$97,406	$86,065	$71,181	$69,900	$63,767	$64,456	$37,696	$50,423	$70,816	$67,273	$485,742
16) Interest Expense	7.96%	Calculated	$31,504	$30,810	$30,863	$31,380	$31,105	$30,060	$30,126	$31,326	$32,502	$33,654	$34,782	$34,531	$32,713	$30,896	$29,259	$27,572	$228,376
17) Income Before Taxes		Calculated	($26,566)	($26,552)	$20,909	$50,190	$53,989	$86,294	$67,280	$54,739	$38,679	$36,246	$28,985	$29,925	$4,985	$19,527	$41,557	$39,701	$257,366
18) Schedule M		Input	($2,896)	($463)	($463)	($463)	($463)	($463)	($463)	($463)	($463)	($463)	($463)	($463)	($463)	($463)	($463)	($463)	($3,370)
19) Taxable Income		Calculated	($29,463)	($27,015)	$20,446	$49,727	$53,526	$85,831	$66,817	$54,276	$38,216	$35,783	$28,522	$29,462	$4,522	$19,064	$41,094	$39,238	$253,996
20) Current Fed/State Tax	40.98%	Calculated	($11,946)	($10,967)	$8,293	$20,169	$21,710	$34,813	$27,101	$22,014	$15,500	$14,513	$11,566	$11,950	$1,834	$7,732	$16,668	$15,916	$103,021
21) Deferred FIT/ITC	35.00%	Input	$1,010	$182	$182	$182	$182	$182	$182	$182	$182	$182	$182	$182	$182	$182	$182	$182	
22) Total Income Taxes		Calculated	($10,936)	($10,785)	$8,455	$20,332	$21,872	$34,975	$27,263	$22,176	$15,662	$14,675	$11,730	$12,112	$1,996	$7,896	$16,830	$16,077	$104,200
23) Net Income Before Preferred		Calculated	($15,630)	($15,767)	$12,454	$29,859	$32,117	$51,319	$40,017	$32,563	$23,016	$21,570	$17,254	$17,813	$2,989	$11,633	$24,727	$23,624	$153,166
Cash Flow																			
24) Net Income Before Preferred		From above	($15,630)	($15,767)	$12,454	$29,859	$32,117	$51,319	$40,017	$32,563	$23,016	$21,570	$17,254	$17,813	$2,989	$11,633	$24,727	$23,624	$153,166
25) Plus Interest Expense		From above	$31,504	$30,810	$30,863	$31,380	$31,105	$30,060	$30,126	$31,326	$32,502	$33,654	$34,782	$34,531	$32,713	$30,896	$29,259	$27,572	$228,376
26) Plus Deferred Taxes		From above	$1,010	$182	$182	$182	$182	$182	$182	$182	$182	$182	$182	$182	$182	$182	$182	$182	
27) Plus Depreciation		From above	$49,884	$51,000	$52,718	$54,965	$56,477	$57,241	$59,187	$62,342	$65,576	$68,880	$72,288	$74,367	$74,980	$76,592	$78,364	$77,151	
28) Plus Retirements		From above	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$10,999	$0	$0	$1,829	
29) Less Construction		External File	$31,843	$37,786	$25,332	$38,503	$23,596	$24,188	$24,793	$25,413	$26,048	$26,699	$27,367	$23,723	$24,316	$24,924	$24,579	$25,193	$203,698
30) Less NOx (SNCR)		External File	$0	$0	$44,239	$32,390	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$59,873
31) Less NOx (SCR) and Scrubber		External File	$0	$0	$0	$0	$0	$0	$72,567	$74,401	$76,361	$78,166	$80,122	$0	$0	$0	$0	$0	
32) Total		Calculated	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	$400,516
Capitalization																			
33) Debt		Input	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	
34) Equity		Input	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	
Investment																			
35) Gross Plant In Service - Steam Gen		Input	$1,574,841	$1,612,638	$1,682,309	$1,753,102	$1,776,700	$1,800,886	$1,899,264	$1,998,082	$2,100,392	$2,205,259	$2,312,746	$2,336,471	$2,349,787	$2,374,711	$2,399,290	$2,422,853	
36) - Hydro		Input	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
37) Accum. Depreciation - Steam Gen		Calculated	$629,812	$680,812	$733,529	$788,494	$844,971	$902,212	$961,399	$1,023,741	$1,089,316	$1,158,207	$1,230,495	$1,304,862	$1,379,862	$1,455,454	$1,531,838	$1,608,989	
38) - Hydro		Input	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
39) Net Plant		Calculated	$945,029	$931,826	$948,880	$964,608	$931,729	$898,676	$936,869	$974,342	$1,011,076	$1,047,052	$1,082,253	$1,031,609	$969,925	$919,257	$867,451	$813,864	
40) Plus Fuel Inventory		Input	$22,140	$22,140	$22,140	$22,140	$22,140	$22,140	$22,140	$22,140	$22,140	$22,140	$22,140	$22,140	$20,603	$20,603	$20,603	$20,603	
41) Plus M&S & Prepayments		Input	$18,000	$18,000	$18,000	$18,000	$18,000	$18,000	$18,000	$18,000	$18,000	$18,000	$18,000	$18,000	$18,000	$18,000	$18,000	$18,000	
42) Less Accum DFIT		Calculated	$10,840	$11,002	$11,164	$11,326	$11,488	$11,650	$11,812	$11,974	$12,136	$12,298	$12,461	$12,623	$12,785	$12,947	$13,109	$13,271	
43) Net Investment		Calculated	$974,329	$960,964	$977,856	$993,422	$960,381	$927,166	$965,197	$1,002,507	$1,039,079	$1,074,894	$1,109,933	$1,059,108	$995,743	$944,913	$892,945	$838,996	
44) Net Investment		Calculated	$974,329																

45) NPV of Cash Flow 2016 - 2030 $97,115

Projected Generation Related Net Stranded Costs
Ohio Power Company
High Gas + Alternative Environment

Stranded Cost Calculation Summary	
NPV of Cash Flow 2001 - 2015	$954,672
NPV of Cash Flow 2016 - 2030	$308,820
Total NPV Cash Flow	$1,263,492
Base	$1,309,382
Net Stranded Costs	$45,889

Income Statement		Source	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	Present Value @ 10.47%
Revenues																			
1) Total GWH Generation		Input	48,624	49,406	50,204	51,012	51,497	51,982	50,698	49,446	48,225	47,034	45,873	45,950	46,027	46,104	46,182	46,259	
2) AEP Price		Input	$23.52	$24.84	$25.81	$27.04	$28.64	$30.23	$30.83	$31.44	$32.06	$32.70	$33.34	$34.34	$35.36	$36.41	$37.49	$38.60	
3) Total Revenues			$1,228,130	$1,306,845	$1,394,855	$1,488,517	$1,590,490	$1,694,483	$1,663,511	$1,633,124	$1,603,293	$1,574,008	$1,545,255	$1,593,288	$1,642,773	$1,693,818	$1,746,445	$1,800,709	
Expenses																			
4) Production Expense excl fuel		Input	$245,453	$255,965	$268,926	$278,380	$292,075	$305,790	$319,883	$334,206	$349,390	$365,263	$381,857	$399,555	$418,072	$437,448	$457,722	$478,936	$2,430,101
5) Fuel Expense		Input	$643,626	$622,064	$600,945	$580,543	$595,752	$610,961	$608,725	$606,490	$604,276	$602,064	$599,860	$609,940	$620,186	$630,610	$641,206	$651,980	$4,504,374
6) Decommissioning/Dismantling		Input	$0	$0	$0	$0	$0	$0	$0	$0	$34,880	$36,731	$24,401	$25,011	$0	$0	$0	$0	
7) SO2 allowance costs		Input	$0	$22,783	$31,071	$29,468	$29,093	$28,588	$22,404	$16,161	$9,847	$3,448	$0	$0	$0	$0	$0	($16,042)	$127,473
8) A&G Expense		Input	$93,278	$94,870	$101,484	$102,737	$103,708	$104,803	$105,907	$108,827	$108,064	$109,114	$110,205	$111,307	$112,420	$113,544	$114,680	$115,826	$760,750
9) Depreciation - Steam Gen	3.40%	Calculated	$90,998	$97,166	$105,150	$109,772	$112,866	$116,097	$124,072	$136,520	$147,989	$159,706	$172,365	$180,088	$183,067	$186,120	$189,249	$192,456	
10) - Hydro	2.70%	Calculated	$2,959	$2,955	$2,955	$2,955	$2,956	$2,956	$2,955	$2,955	$2,955	$2,955	$2,955	$2,955	$2,955	$2,955	$2,955	$2,955	
11) Retirements			$0	$0	$0	$0	$0	$0	$0	$0	$58,760	$0	$18,413	$0	$0	$0	$0	$0	
12) Taxes - NOx and Scrubber	0.15%	Calculated	$0	$41	$71	$80	$96	$103	$103	$308	$518	$733	$953	$1,179	$1,179	$1,179	$1,179	$1,179	$3,006
13) Taxes Other - Other		Input	$78,147	$78,629	$42,536	$42,851	$43,172	$43,500	$43,835	$44,177	$44,527	$44,884	$45,248	$45,620	$46,000	$46,387	$46,783	$47,186	$358,576
14) Total Expenses		Calculated	$1,154,761	$1,174,474	$1,151,120	$1,148,786	$1,179,618	$1,212,798	$1,227,683	$1,247,451	$1,361,175	$1,323,895	$1,358,257	$1,375,655	$1,383,882	$1,418,243	$1,453,773	$1,474,477	$9,297,572
15) Operating Income		Calculated	$73,378	$134,371	$243,735	$339,751	$410,871	$481,665	$435,828	$385,673	$242,118	$250,111	$186,997	$217,613	$258,891	$276,572	$292,671	$326,232	$2,227,588
16) Interest Expense	7.18%	Calculated	$38,150	$39,992	$43,780	$44,549	$43,748	$43,312	$46,549	$53,272	$58,639	$63,884	$69,756	$71,171	$68,422	$65,649	$62,852	$60,030	$382,831
17) Income Before Taxes		Calculated	$35,228	$94,379	$199,955	$295,202	$367,223	$438,353	$389,279	$332,401	$183,479	$186,227	$119,239	$146,442	$190,469	$209,923	$229,819	$266,201	$1,844,757
18) Schedule M		Input	$3,466	$3,466	$3,466	$3,466	$3,466	$3,466	$3,466	$3,466	$3,466	$3,466	$3,466	$3,466	$3,466	$3,466	$3,466	$3,466	$25,070
19) Taxable Income		Calculated	$38,694	$97,845	$203,421	$298,668	$370,689	$441,819	$392,745	$335,867	$186,944	$189,693	$122,705	$149,908	$193,935	$213,389	$233,285	$269,667	$1,870,426
20) Current Fed/State Tax	40.55%	Calculated	$15,694	$39,686	$82,506	$121,140	$150,351	$179,202	$159,297	$136,229	$75,825	$76,940	$49,769	$60,803	$78,660	$86,551	$94,620	$109,377	$758,645
21) Deferred FIT/ITC	35.00%	Input	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	
22) Total Income Taxes		Calculated	$14,481	$38,473	$81,294	$119,927	$149,138	$177,989	$158,084	$135,014	$74,612	$75,726	$48,556	$59,589	$77,447	$85,338	$93,407	$108,164	$749,881
23) Net Income Before Preferred		Calculated	$20,747	$55,906	$118,661	$175,275	$218,084	$260,364	$231,195	$197,386	$108,867	$110,501	$70,683	$86,852	$113,022	$124,586	$136,412	$158,037	$1,095,096
Cash Flow																			
24) Net Income Before Preferred		From above	$20,747	$55,906	$118,661	$175,275	$218,084	$260,364	$231,195	$197,386	$108,867	$110,501	$70,683	$86,852	$113,022	$124,586	$136,412	$158,037	$1,095,096
25) Plus Interest Expense		From above	$38,150	$39,992	$43,780	$44,549	$43,748	$43,312	$46,549	$53,272	$58,639	$63,884	$69,756	$71,171	$68,422	$65,649	$62,852	$60,030	$382,831
26) Plus Deferred Taxes		From above	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	
27) Plus Depreciation		From above	$93,957	$100,121	$108,106	$112,727	$115,821	$118,053	$127,027	$139,475	$150,844	$162,661	$175,320	$183,044	$186,022	$189,075	$192,204	$195,412	
28) Plus Retirements		From above	$0	$0	$0	$0	$0	$0	$0	$0	$58,760	$0	$18,413	$0	$0	$0	$0	$0	
29) Less Construction			$97,735	$102,566	$80,117	$57,183	$82,018	$94,319	$96,877	$81,991	$83,939	$82,352	$94,411	$98,521	$98,664	$90,901	$93,174	$95,503	$841,905
30) Less NOx (SNCR)		External File	$0	$182,512	$124,436	$16,173	$10,982	$4,839	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$241,454
31) Less NOx (SCR) and Scrubber			$0	$0	$0	$0	$0	$0	$273,430	$280,268	$287,272	$294,454	$301,816	$0	$0	$0	$0	$0	
32) Total		Calculated	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	$954,672
Capitalization																			
33) Debt		Input	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	
34) Equity		Input	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	
Investment																			
35) Gross Plant In Service - Steam Gen		Input	$2,725,280	$2,890,364	$3,194,915	$3,282,272	$3,385,152	$3,484,110	$3,834,217	$4,196,374	$4,508,835	$4,865,641	$5,253,454	$5,339,975	$5,428,858	$5,519,580	$5,612,733	$5,708,238	
36) - Hydro		Input	$109,453	$109,453	$109,453	$109,453	$109,453	$109,453	$109,453	$109,453	$109,453	$109,453	$109,453	$109,453	$109,453	$109,453	$109,453	$109,453	
37) Accum. Depreciation - Steam Gen		Calculated	1,587,274	$1,684,440	$1,789,590	$1,899,362	$2,012,028	$2,128,126	$2,252,197	$2,388,717	$2,536,706	$2,696,412	$2,868,777	$3,048,865	$3,231,932	$3,418,051	$3,607,300	$3,799,757	
38) - Hydro		Input	$44,176	$47,131	$50,086	$53,042	$55,997	$58,952	$61,907	$64,863	$67,818	$70,773	$73,728	$76,684	$79,639	$82,594	$85,549	$88,504	
39) Net Plant		Calculated	$1,203,289	$1,368,245	$1,464,692	$1,419,321	$1,406,580	$1,388,485	$1,629,566	$1,852,247	$2,013,764	$2,227,909	$2,420,402	$2,323,879	$2,226,541	$2,128,367	$2,029,337	$1,929,428	
40) Plus Fuel Inventory		Input	$92,929	$92,929	$92,929	$92,929	$92,929	$92,929	$92,929	$92,929	$80,052	$80,052	$80,052	$80,052	$80,052	$80,052	$80,052	$80,052	
41) Plus M&S & Prepayments		Input	$38,000	$38,000	$38,000	$38,000	$38,000	$38,000	$38,000	$38,000	$38,000	$38,000	$38,000	$38,000	$38,000	$38,000	$38,000	$38,000	
42) Less Accum DFIT		Calculated	$24,836	$23,623	$22,410	$21,197	$19,984	$18,771	$17,558	$16,345	$15,132	$13,919	$12,705	$11,492	$10,279	$9,066	$7,853	$6,640	
43) Net Investment		Calculated	$1,309,382	$1,475,551	$1,573,211	$1,529,053	$1,517,525	$1,498,644	$1,742,937	$1,966,832	$2,116,684	$2,332,042	$2,525,748	$2,430,438	$2,334,313	$2,237,353	$2,139,535	$2,040,839	
44) Net Investment		Calculated	$1,309,382																

45) NPV of Cash Flow 2016 - 2030 $308,820

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Decommissioning Costs

Ohio Power				
PLANT	Decom Cost - 1994$	Decom Year	1/2 Decom Cost In Decom Year$	1/2 Decom Cost In (Decom Year + 1)$
Kammer	31,975	2,008	22,590	23,155
Musk 1-4	17,368	2,008	12,270	12,577
Sporn	32,875	2,010	24,401	25,011
Mitchell	25,779	2,031	32,138	32,942
Amos	30,379	2,033	39,790	40,785
Gavin	30,834	2,035	42,430	43,491
Cardinal	9,540	2,027	10,775	11,044
Musk 5	12,068	2,028	13,971	14,320

Columbus Southern				
Plant	Decom Cost - 1994$	Decom Year	1/2 Decom Cost In Decom Year$	1/2 Decom Cost In (Decom Year + 1)$
Picway	4,328	2015	3,634	3,725
Conesville	4,328	2012	3,375	3,459
Conesville	5,712	2012	4,455	4,566
Beckjord	11,736	2029	13,926	14,274
Conesville	12,983	2012	10,124	10,377
Conesville	12,983	2033	17,004	17,429
Stuart	3,462	2034	4,648	4,764
Conesville	21,049	2038	31,193	31,972
Conesville	1,835	2038	2,719	2,787
Zimmer	11,425	2051	23,339	23,923

SO_2 Allowance Data

Allowances Issued By EPA

Year	OPCo	CSPCo
1998	188,043	70,211
1999	458,248	88,554
2000	231,975	63,139
2001	231,975	63,139
2002	231,975	63,139
2003	231,975	63,139
2004	231,975	63,139
2005	231,975	63,139
2006	231,975	63,139
2007	231,975	63,139
2008	231,975	63,139
2009	231,975	63,139
2010	230,385	59,942
2011	230,385	59,942
2012	230,385	59,942
2013	230,385	59,942
2014	230,385	59,942
2015	230,385	59,942
2016	230,385	59,942
2017	230,385	59,942
2018	230,385	59,942
2019	230,385	59,942
2020	230,385	59,942
2021	230,385	59,942
2022	230,385	59,942
2023	230,385	59,942
2024	230,385	59,942
2025	230,385	59,942
2026	230,530	59,942
2027	230,530	59,942
2028	230,864	59,942
2029	230,864	59,942

Allowances (quantity) at end of 1998

OPCo	CSPCo
188,043	70,211

Ohio Power Annual Costs

Year	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
A&G Expense	99,860	93,279	94,870	101,464	102,737	103,708	104,803	105,907	106,627	108,064	109,114	110,205	111,307	112,420	113,544	114,680	115,826
Write-off / Retirements										58,750		18,413					
Construction Costs	114,335	97,735	102,566	80,117	57,183	92,019	94,319	96,677	81,891	83,939	82,352	84,411	86,521	88,684	90,901	93,174	95,503
Schedule M	4,452	3,466	3,466	3,466	3,466	3,466	3,466	3,466	3,466	3,466	3,466	3,466	3,466	3,466	3,466	3,466	3,466
Other Taxes	77,672	78,147	78,629	42,536	42,851	43,172	43,500	43,835	44,177	44,527	44,884	45,248	45,620	46,000	46,387	46,783	47,186

Columbus Southern Power Annual Costs

Year	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
A&G Expense	65,985	61,881	66,843	65,998	69,905	70,470	73,034	71,390	75,668	82,786	75,590	76,724	77,874	79,043	80,228	81,432	82,653
Write-off / Retirements														10,999			1,829
Construction Costs	19,670	31,943	37,796	25,332	38,503	23,598	24,188	24,793	25,413	26,048	26,699	27,367	23,723	24,316	24,924	24,579	25,193
Schedule M	(2,378)	(2,886)	(463)	(463)	(463)	(463)	(463)	(463)	(463)	(463)	(463)	(463)	(463)	(463)	(463)	(463)	(463)
Other Taxes	40,645	41,108	42,707	13,663	14,163	14,679	15,216	15,774	16,351	16,950	17,573	18,218	18,885	19,576	20,293	21,035	21,805

Gross Plant Data, Depreciation Rates and Tax Rates

Data Type	Ohio Power	Columbus Southern
1999 Steam Gen Gross Plant in Service	$2,627,551	$1,542,898
1999 Hydro Gross Plant in Service	$109,703	
2000 - 2015 Hydro Gross Plant in Service	$109,453	
1999 Accumulated Depreciation - Steam	$1,505,142	$589,323
2000 Accumulated Depreciation - Steam	$1,587,274	$629,812
1999 Accumulated Depreciation - Hydro	$41,388	
2000 Accumulated Depreciation - Hydro	$44,176	
Fuel Inventory, All Years	$92,929	$22,140
M&S & Prepayments	$38,000	$18,000
Accum DFIT	$25,647	$10,840
Steam Gen Depreciation Rate	3.4%	3.2%
Hydro Depreciation Rate	2.7%	
Inflation Rate	2.5%	2.5%
Debt Interest Rate	7.18%	7.96%

Sources: *Forecasted Financial Statements for OPCO's 1999 Approved Budget*
Forecasted Financial Statements for CSPCO's 1999 Approved Budget

Tax Rates		
Before Deregulation	*Federal*	35.00%
	State	4.75%
After Deregulation	*Combined Effective Rate*	40.56%

NOx Capital Cost Data

	% Labor Cost	% Material Cost	In Service Date
AE-FLGR	100%	0%	2003
Do Nothing			
Gas 100	100%	0%	2003
OFA_SNCR	100%	0%	2003
PRB OFF_GR	100%	0%	2003
PRB OFF_OFA_SNC	100%	0%	2003
PRB100_OFA_SNCR	100%	0%	2003
SCR	43%	57%	Varies
SNCR	100%	0%	2003
	Inflated	Not Inflated	

Inflation	2.50%
Case	[redacted]
$ in	1999

unit	Technology	In Service Date	Total Capital	Capital Labor	Capital Material	2000	2001	2002	2003	2004	2005	2006	2007	Company
Amos 1	SNCR	2003	9600	100%	0%	$ -	$ -	$ 6,031	$ 4,415	$ -	$ -	$ -	$ -	
Amos 2	SNCR	2003	9600	100%	0%	$ -	$ -	$ 6,031	$ 4,415	$ -	$ -	$ -	$ -	
Amos 3	SCR	2002	100100	43%	57%	$ -	$ 40,896	$ 29,944	$ -	$ -	$ -	$ -	$ -	OP
Beckjord 6	Do Nothing	0	0	0%	0%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	CSPC
Big Sandy 1	Do Nothing	0	0	0%	0%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Big Sandy 2	SNCR	2005	9600	100%	0%	$ -	$ -	$ -	$ -	$ 6,336	$ 4,639	$ -	$ -	
Cardinal 1	SNCR	2003	0.6	100%	0%	$ -	$ -	$ 0	$ 0	$ -	$ -	$ -	$ -	
Clinch R 1	SNCR	2003	3760	100%	0%	$ -	$ -	$ 2,362	$ 1,729	$ -	$ -	$ -	$ -	
Clinch R 2	SNCR	2003	3760	100%	0%	$ -	$ -	$ 2,362	$ 1,729	$ -	$ -	$ -	$ -	
Clinch R 3	SNCR	2003	3760	100%	0%	$ -	$ -	$ 2,362	$ 1,729	$ -	$ -	$ -	$ -	
Conesville 1	Do Nothing	0	0	0%	0%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	CSPC
Conesville 2	Do Nothing	0	0	0%	0%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	CSPC
Conesville 3	Do Nothing	0	0	0%	0%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	CSPC
Conesville 4	Do Nothing	2003	0	0%	0%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	CSPC
Conesville 5	Do Nothing	0	0	0%	0%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	CSPC
Conesville 6	Do Nothing	0	0	0%	0%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	CSPC
Gavin 1	SCR	2002	94900	43%	57%	$ -	$ 58,161	$ 42,582	$ -	$ -	$ -	$ -	$ -	OP
Gavin 2	SCR	2002	94900	43%	57%	$ -	$ 58,161	$ 42,582	$ -	$ -	$ -	$ -	$ -	OP
Glen Lyn 5	Do Nothing	0	0	0%	0%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Glen Lyn 6	Do Nothing	0	0	0%	0%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Kammer 1	Do Nothing	0	0	0%	0%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	OP
Kammer 2	Do Nothing	0	0	0%	0%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	OP
Kammer 3	Do Nothing	0	0	0%	0%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	OP
Kanawha 1	SNCR	2003	3200	100%	0%	$ -	$ -	$ 2,010	$ 1,472	$ -	$ -	$ -	$ -	
Kanawha 2	SNCR	2003	3200	100%	0%	$ -	$ -	$ 2,010	$ 1,472	$ -	$ -	$ -	$ -	
Mitchell 1	SNCR	2004	9600	100%	0%	$ -	$ -	$ -	$ 6,181	$ 4,526	$ -	$ -	$ -	OP
Mitchell 2	SNCR	2005	9600	100%	0%	$ -	$ -	$ -	$ -	$ 6,336	$ 4,639	$ -	$ -	OP
Mountaineer	SNCR	2003	15600	100%	0%	$ -	$ -	$ 9,800	$ 7,175	$ -	$ -	$ -	$ -	
Muskingum 1	SNCR	2003	3280	100%	0%	$ -	$ -	$ 2,060	$ 1,509	$ -	$ -	$ -	$ -	OP
Muskingum 2	Do Nothing	0	0	0%	0%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	OP
Muskingum 3	Do Nothing	0	0	0%	0%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	OP
Muskingum 4	Do Nothing	0	0	0%	0%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	OP
Muskingum 5	Gas Reburn	2002	8635	#N/A	#N/A	$ -	$ 5,292	$ 3,875	$ -	$ -	$ -	$ -	$ -	OP
Picway 5	Do Nothing	0	0	0%	0%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	CSPC
Sporn 1	Do Nothing	0	0	0%	0%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Sporn 2	Do Nothing	0	0	0%	0%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	OP
Sporn 3	Do Nothing	0	0	0%	0%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Sporn 4	Do Nothing	0	0	0%	0%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	OP
Sporn 5	SNCR	2003	5400	100%	0%	$ -	$ -	$ 3,392	$ 2,484	$ -	$ -	$ -	$ -	OP
Rockport 1	SNCR	2003	26000	100%	0%	$ -	$ -	$ 16,333	$ 11,958	$ -	$ -	$ -	$ -	
Rockport 2	SNCR	2005	26000	100%	0%	$ -	$ -	$ -	$ -	$ 17,160	$ 12,563	$ -	$ -	
Stuart 1	SCR	2003	14744	43%	57%	$ -	$ -	$ 9,262	$ 6,781	$ -	$ -	$ -	$ -	CSPC
Stuart 2	SCR	2003	14744	43%	57%	$ -	$ -	$ 9,262	$ 6,781	$ -	$ -	$ -	$ -	CSPC
Stuart 3	SCR	2003	14744	43%	57%	$ -	$ -	$ 9,262	$ 6,781	$ -	$ -	$ -	$ -	CSPC
Stuart 4	SNCR	2003	2432	100%	0%	$ -	$ -	$ 1,528	$ 1,119	$ -	$ -	$ -	$ -	CSPC
Tanners Ck 1	Do Nothing	0	0	0%	0%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Tanners Ck 2	Do Nothing	0	0	0%	0%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Tanners Ck 3	SNCR	2003	3280	100%	0%	$ -	$ -	$ 2,060	$ 1,509	$ -	$ -	$ -	$ -	
Tanners Ck 4	PRB100_OFA	2003	43131.05816	100%	0%	$ -	$ -	$ 27,094	$ 19,837	$ -	$ -	$ -	$ -	
Zimmer	SCR	2003	23780	43%	57%	$ -	$ -	$ 14,928	$ 10,928	$ -	$ -	$ -	$ -	CSPC
Stuart, Zimmer assumed to be completed by spring 2003.			TOTAL			$ -	$162,512	$247,129	$100,003	$ 34,357	$ 21,841	$ -	$ -	

	2000	2001	2002	2003	2004	2005	2006	2007
Ohio Power Capital Costs	$ -	$162,512	$124,435	$ 10,173	$ 10,862	$ 4,639	$ -	$ -
Columbus Capital Costs	$ -	$ -	$ 44,239	$ 32,390	$ -	$ -	$ -	$ -

	2000	2001	2002	2003	2004	2005	2006	2007								
Nox Costs that are applicable to tax	-	27,266	19,962	6,181	10,862	4,639	-	-								
Total Tax at .15%	-	40.90	70.84	80.11	96.41	103.36	103.36	103.36	103.36	103.36	103.36	103.36	103.36	103.36	103.36	103.36

Ohio Power and Columbus Southern Power Scrubber Cost Data

	1997 $	
SCR Capital Cost	$69.70	Source: EPA report on environmental costs
Scrubber Capital Cost	$200.00	Source: EPA report on environmental costs
Inflation rate	2.5	

Columbus & Southern Power Units

[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	2006	2007	2008	2009	2010	check
Conesville 3	162	2012	ST	BIT	100				0	0	0	$0	$0	$0	$0	$0	
Conesville 4	842	2033	ST	BIT	44		25,514	73,211	31,883	91,430	123,293	$25,275	$25,907	$26,555	$27,219	$27,899	$125,085.00
Conesville 5	444	2038	ST	BIT	100		23,410		29,235	0	29,235	$5,993	$6,143	$6,297	$6,454	$6,615	$51,339.97
Conesville 6	444	2038	ST	BIT	100		23,410		29,235	0	29,235	$5,993	$6,143	$6,297	$6,454	$6,615	$51,339.97
J M Stuart 1	610	2034	ST	BIT	26	14,744		31,730	0	39,627	39,627	$8,124	$8,327	$8,535	$8,748	$8,967	$29,961.82
J M Stuart 2	610	2034	ST	BIT	26	14,744		31,730	0	39,627	39,627	$8,124	$8,327	$8,535	$8,748	$8,967	$29,961.82
J M Stuart 3	610	2034	ST	BIT	26	14,744		31,730	0	39,627	39,627	$8,124	$8,327	$8,535	$8,748	$8,967	$29,961.82
J M Stuart 4	610	2034	ST	BIT	26		11,058	31,730	13,810	39,627	53,437	$10,955	$11,228	$11,509	$11,797	$12,092	$54,213.49
W H Zimmer 1	1,426	2051	ST	BIT	25	23,760			0	0	0	$0	$0	$0	$0	$0	$0.00
Walter Beckjor 6	434	2029	ST	BIT	13		2,883	11,812	3,601	14,751	18,352	$3,762	$3,856	$3,953	$4,051	$4,153	$17,478.68
																	$0.00
TOTAL	6,191					67,992	88,274	211,944	107,746	264,689	354,081	72,887	74,401	76,261	78,168	80,122	

Ohio Power Units

[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	2006	2007	2008	2009	2010	
Cardinal 1	615	2027	ST	BIT	100	0	42,879	123,040	53,551	153,660	207,211	$42,478	$43,540	$44,629	$45,744	$46,888	check
Gen J M Gavin 1	1,300	2035	ST	BIT	100	94,900	0	0	0	0	0	$0	$0	$0	$0	$0	$0.00
Gen J M Gavin 2	1,300	2035	ST	BIT	100	94,900	0	0	0	0	0	$0	$0	$0	$0	$0	$0.00
John E Amos 3	1,300	2033	ST	BIT	66	100,100	0	171,600	0	214,305	214,305	$43,933	$45,031	$46,157	$47,310	$48,493	$182,035.40
Mitchell-WV 1	816	2031	ST	BIT	100	0	56,896	163,260	71,055	203,889	274,945	$56,364	$57,773	$59,217	$60,698	$62,215	$278,940.55
Mitchell-WV 2	816	2031	ST	BIT	100	0	56,896	163,260	71,055	203,889	274,945	$56,364	$57,773	$59,217	$60,698	$62,215	$278,940.55
Muskingum Rive 5	615	2028	ST	BIT	100	0	42,879	123,040	53,551	153,660	207,211	$42,478	$43,540	$44,629	$45,744	$46,888	$210,222.01
Phillip Sporn 5	496		ST	BIT	100	0	25,144	99,120	31,401	123,787	155,188	$31,814	$32,609	$33,424	$34,260	$35,116	$148,738.48
																	$0.00
TOTAL	7,259					289,900	224,695	843,320	280,613	1,053,191	1,333,804	273,430	280,266	287,272	294,454	301,816	

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Year							$138,418	$139,828	$143,324	$146,907	$150,580					
Ohio Scrubber Costs																
	0	0	0	0	0	0	0	205	414	629	850	1,076	1,076	1,076	1,076	1,076
Scrubber Tax (.15%)																

FORTNIGHTLY

November 1, 1997

SECTION: FEATURE, Pg. 46

LENGTH: 2455 words

HEADLINE: Unbundling Capital Costs: It Doesn't Add Up; G + T + D=? Why the sum of the future parts is greater than the present whole.

BYLINE: By Robert G. **Rosenberg;** Robert **Rosenberg,** principal of Benrose Economic Consultants, New York, has more than 25 years of experience in regulatory economics.

BODY:

GENCO, TRANSCO, DISCO. IF THAT IS the future, then rates collected formerly by the integrated electric company--with its generation, transmission and distribution functions--will have to be determined again for each segment. One aspect of these rates--the cost of capital--has generated significant controversy. n1

n1 See, for example, these articles published in Public Utilities Fortnightly: Susan Stratton Morse, Meg Meal and Melissa Lavinson, "Rate Unbundling: Are We There Yet?," Feb. 15, 1996, p. 30; Joseph F. Brennan and J. Robert Malko, "Rate Unbundling: Are We There Yet? A Reality Check," June 1, 1996, p. 30.

The task becomes particularly difficult, for example, if regulators should attempt to set the cost of capital for distribution before the integrated utility spins off that segment, or if a distribution company operates as a separate subsidiary controlled by a public utility holding company that also includes generation and transmission affiliates. Comparable-risk proxy companies may prove impossible to find in either case: Subsidiaries do not issue their own stock to the public; holding companies, which do issue stock, will still reflect the combined risk of generation, transmission and distribution, if not other businesses as well.

Some authors have turned to the telephone or gas industries for analogies of how risks will change in a restructured electric industry. n2 Another method would start with the integrated utility's cost of capital and partition it into estimates for the generation, transmission and distribution functions. This approach assumes the capital costs of these segments on a standalone basis to reflect a weighted average of the integrated company. Michael T. Maloney, Robert E. McCormick and Cleve B. Tyler described this approach in a recent article. n3

n2 See, David P. Wagener, "Letting Go of Electric Generation," Public Utilities Fortnightly, Feb. 15, 1995, p. 33; Morse et al. and Brennan et al., supra, note 1.

n3 "The Wires Charge: Risk and Rates For the Regulated Distributor," Public Utilities Fortnightly, Sept. 1, 1997, p. 26.

Such an assumption ignores two realities. First, the newly formed independent segments of an integrated electric utility will prove riskier. Second, because of restructuring, each segment will face increased uncertainty.

Maloney et al. assume a beta for the wires business of 0.4 plus an equity ratio of 38.5 percent. These assumptions seem unwarranted. The mere act of splitting the business apart will make each of the newly formed independent segments riskier in the future. Disaggregation will not play out as a zero-sum game.

Distribution: No Track Record

Investment advisory services (such as the Value Line Investment Survey and Standard & Poor's) consider small companies a risky proposition. These new, disaggregated entities will be smaller than the aggregated utility from which they emerged. n4 By disaggregating, companies will lose the benefits of intracompany diversification and vertical integration. New management may come on board. The new companies will start up without a track record.

n4 Even if a function (e.g., distribution) is established as a subsidiary of a holding company, such subsidiary will have to be looked at as on a standalone basis and thus size does remain a relevant factor for risk analysis.

Without a script for restructuring, legislators or regulators could succumb to political pressure, creating event risk for disaggregated distribution companies. n5 Some jurisdictions face an imperative for lower rates, with cost being secondary. n6

n5 This discussion focuses on the standalone distribution company. However, risk also will increase for both transmission and generation companies. For example, generation companies will no longer have a nearly assured market and will face substantial competition. That risk coupled with the asset concentration generating companies will face will increase volatility in a deregulated market.

n6 Of course, if costs are too high, rate reduction is justified. However, the risk discussed here is that the political drive for lower rates will prevent utilities from having a fair opportunity to recover even reasonable costs.

Moreover, distribution companies may be saddled with the job of billing for stranded costs and will be subject to all the other remnants of traditional regulation, such as lifeline rates, liberal (ratepayer-oriented) disconnect policies, etc. During the transition, and possibly after that, the "distribution" utility may take on obligation to purchase power for an unknown and varying group of its ratepayers as a provider of last resort. n7 This residual obligation presents three types of risk to a distribution company:

. Resource planning for an uncertain customer base;

. A high-cost customer base; n8 and

. No compensation for purchased-power risk.

n7 In addition, in certain proposed restructuring plans, even though most generation will be spun off, the distribution company will retain ownership of, or affiliation with, nuclear plants. Such an arrangement obviously has substantial risks including that of asset concentration, lack of fuel diversity and dealing with the Nuclear Regulatory Commission.

n8 Ratepayers with poor payment records are likely to be forced away from other power providers and end up served by the distribution company. Expect especially high collection expenses and bad debt for this group.

(Under current regulation, utilities can receive, at best, one-for-one recovery of purchased-power costs. At worst, they incur a loss if they purchase too much power or if price is deemed too high but receive no compensation for this risk. Fixed-cost purchased-power obligations serve as debt-equivalent obligations. Distribution companies must augment their equity ratios to offset the increase in leverage. n9)

n9 See, Robert **Rosenberg,** "Purchased Power: Risk Without Return?" Public Utilities Fortnightly, Feb. 15, 1996, p. 36.

Granted, the distribution company will retain a monopoly in its service territory. Even so, it may face competition from some unexpected areas, such as distributed generation. The multi-fuel enterprises that are forming also may compete for customers.

Distribution companies may find it difficult to compete when forced to collect surcharges for stranded costs (related to generation) or public benefits through a wires charge. Even if broken out separately on the bill, these charges will mark the disco as a political target. Ratepayers likely will associate the distribution utility with high costs.

PBR: No Panacea

To this mix add the specter of performance-based rate making, which exposes the distribution company to greater risk through (1) direct linkage to macroeconomic trends, (2) longer terms without rate review and (3) possible uneven risk/reward formulas.

Under a typical PBR plan, distribution rates will change with inflation and productivity indexes, adjusted for reward or penalty according to service quality. n10 A firm operating under PBR must rely on generalized indexes to cover its increase in costs. These macroeconomic indexes fluctuate more with the general economy than with utility-specific trends. Their inputs are measured in a much greater scale than a single firm. If the company's costs, even under efficient management, are not well correlated with the indexes chosen to govern the plan, then the firm will see volatile earnings, with higher risk for shareholders. Not only will earnings become more variable under PBR; the covariability likely will increase as well, increasing systematic risk and beta, too.

n10 In some instances, penalty-only service quality standards are established. This clearly increases the risk to the company since its return prospects are negatively skewed.

Also, a typical PBR plan runs for up to five years--a longer cycle than normal for rate cases. Unanticipated events could intervene. Many PBR plans implicitly assume that interest rates generally will remain the same during the term of the plan. However, if the cost of capital rises substantially, then a company may be locked in for several years, exposing it to substantial risk. Interest rates, for example, have remained relatively benign over the past few years, but are unlikely to remain so in the future.

Lastly, a PBR regime ties company earnings to efficiency and some stated earnings sharing arrangement, but the sharing formula can be asymmetric, which may increase risk substantially. Even if the firm earns what regulators perceive to be high rates of return under a PBR plan, then, in the subsequent PBR plan, the sharing and/or productivity targets may be adjusted upward. This ratchet effect nearly ensures that the standalone distribution company will earn lower returns in the future. This risk, often called recontracting, means that the company is effectively capped on the upside, but not on the downside--presenting it with an asymmetrical return prospect over the long run.

Already one can see that Maloney et al. begin their partitioning of cost of capital with a faulty assumption--that the sum of the three future parts (G, T & D) will, on a weighted-average basis, equal the current cost of capital of the integrated utility. Nevertheless, for the sake of analysis, let's assume the proposition, to discover why their further assumptions also are faulty.

Beta: Not Partitioned Correctly

Maloney et al. start their analysis by assuming that the generation portion of the business will have a beta of 0.9 and the wires portion (a combination of transmission and distribution) will have a beta of only 0.4. They offer no support for this partitioning, but do concede that additional research into this matter is needed. In fact, out of about 1,700 companies followed by the Value Line Investment Survey, only five have a beta of 0.4 or lower. n11 At first glance, the assumption of a beta as low as 0.4 for the wires business seems somewhat extreme.

n11 It is worthwhile to note that these five companies have a median debt-equity ratio of only 0.4, compared to the 1.6 debt-equity ratio which Maloney et al. assume for the wires business. In fact, there are only 16 companies reported by Value Line with betas of less than 0.5 and these companies, too, have a median debt-equity ratio of only 0.4.

Maloney et al. propose that the beta of an integrated electric utility (B[i]) is a weighted average of the implicit unobservable betas of the generation business (B[g]) and the wires business [ILLEGIBLE WORD] with the weights (W[g] and [ILLEGIBLE WORD], respectively) reflecting the relative portion of total book value of each segment. In equation form, this can be expressed as follows:

[SEE ILLUSTRATION IN ORIGINAL]

B[i] is readily available from financial information providers and W[g] and [ILLEGIBLE WORD] are easily calculated from company financial statements. Given that B[i], W[g] and [ILLEGIBLE WORD] are known, B[g] and [ILLEGIBLE WORD] can be determined using statistical optimization procedures which produce the lowest statistical error (i.e., the lowest mean square error) in predicting B[i]. Such calculations lead to an estimate of a partitioned wires beta of 0.6, n12 which is much greater than the 0.4 beta employed by Maloney et al. in their calculations. Using the Maloney et al. assumptions of a 6.6 percent risk-free rate and a 7 percent expected return on the market, a wires beta of 0.6 produces an estimate of the current cost of equity of 10.8 percent for this segment. This figure is much higher than the estimate of 9.4 percent given by Maloney et al. Furthermore, it must be recognized that the partitioned 10.8 percent wires cost of equity estimate is understated given that it assumes (incorrectly) that the risk of an independent wires business will not rise compared with current levels.

n12 The partitioning of the current integrated beta (0.73 on average) produced segment beta estimates of 0.85, 0.60 and 0.67 for generation, wires and gas distribution, respectively. (Gas distribution represents nearly 10 percent of net utility book value, on average, and was thus included in the analysis.) The mean square error of these segment betas is less than half of that associated with the Maloney et al. hypothesized segment betas.

Maloney et al. also perform a capital structure partitioning of the integrated electric utility and derive a debt-equity ratio for the wires and generation businesses of 1.6 and 0.6, respectively. They assume that the future debt-equity ratios of the then independent generation and wires businesses will, when combined on a weighted average basis, equal the current debt-equity ratio of the integrated electric utility. However, given that the business risks of both the generation and wires segments will increase under restructuring compared with the level that exists now, those segments, as independent entities, will have lower debt capacity.

A 1.6 debt-equity ratio for wires represents an equity ratio of about 38.5 percent--down 11.5 percentage points from the approximate 50 percent common equity ratio of integrated electric utilities today. n13 Maloney et al. indicate they obtain the 1.6 debt-equity ratio for the wires business from the ratio for air transport they found in prior research. However, the portion of the research to which they cite merely determined which industries, back in the mid-1980s, had the highest debt-equity ratios. No nexus appears to exist linking the air transport industry of more than 10 years ago and the wires business today. In fact, the air transport industry, per Value Line data, has a debt-equity ratio of about 0.9 today. That ratio is projected to decline to nearly 0.3 in the future.

n13 In an article by Eugene F. Brigham, Louis C. Gapinski and Dana A. Aberwald, "Capital Structure, Cost of Capital, and Revenue Requirements," Public Utilities Fortnightly, Jan. 8, 1987, p. 15, it was suggested that a percentage point change in the debt ratio results in approximately a 12-basis-point change in the cost of equity. Using these figures, a company with an equity ratio of 38.5 percent would have a cost of equity about 140 basis points higher than a company with a 50 percent equity ratio, other things being equal.

The risk of the distribution business only will climb with restructuring. So too, will the risks of the generation and transmission segments. The sum of these future parts cannot equal the whole of today's integrated electric industry.

LANGUAGE: ENGLISH

E-mails Related to Working Papers for Exhibit JHL-2:

Internal AG E-mail Regarding AEP Cash Flows After Year 2015 (12/9/99):

Gentlemen,
John, Ed and I discussed the issue of the timeframe and rate of decline of ca sh flows in the salvage value calculation. John is comfortable supporting the s traightline to zero over 15 years assumption. Could the two of you coordinate t o implement this assumption? Thanks.

Peter

E-mail from D. Buck at AEP Regarding Taxes on NOx and Scrubber Investments (12/16/99):

Ajay,

This is to clarify the taxes on the NOx and scrubber investments. In Ohio the environmental investments are not taxed. For the plants in West Virginia the tax is 5% of the cost x 3$ per every 100$'s. If you have questions please call me.

Doug

E-mail from F. Messner at AEP Regarding Escalation of A&G Data and Tax Data (12/9/99):

Brian,

I think it's reasonable to continue escalating the trend in the data after 2009.

I will let Doug and Ollie know that is what is being done.

Franz

Hi Franz, I have been asked by Peter Griffes to update our cash flow analyses with the A&G and tax data that you sent earlier today. The new data has values through the year 2009. What escalation rate should we use to extrapolate through the year 2015? A&G expenses grow at about 1% per year through 2009. 'Other Taxes' grow at constant rates for each of the two companies as well (.8% for OPCo, 3.6% for CSPCo).

Please feel free to email me (bgreenblatt@ag-inc.com) or call me at (415) 263-2220 with any questions.

Thank you very much for your time and consideration.

Brian L. Greenblatt
Senior Research Analyst
Analysis Group / Economics
Two Embarcadero Center, Suite 1160
San Francisco, CA 94111

Discount Rate Calculations	
Leveraged Beta	0.85
Tax Rate	40.56%
Debt/Equity	1
Unleveraged Asset Beta	0.53
Tax Rate	40.56%
Debt/Equity	0.67
Releveraged Asset Beta	0.74
Market Risk Premium	9.85%
Risk Free Rate	5.33%
Cost of Equity Capital	12.66%
Cost of Debt - CSP	7.96%
Cost of Debt - OCP	7.18%
WACC - CSP	10.78%
WACC - OCP	10.47%

Cash Flow Data		1999	2000	2001	2002	2003	2004	2005	2006
Revenues									
GWH Generation			16,238	16,309	16,380	16,451	16,541	16,631	16,403
AEP Price			23.52	23 76	24.01	24.26	25.53	26.79	27 58
PROSYM Revenues			396,780	404,538	412,448	420,512	445,283	470,853	478,083
Expenses									
O&M			59,059	61,133	63,279	65,501	68,766	72,830	74,846
Fuel Expense			179,910	180,578	181,249	181,922	186,411	190,981	194,245
Emissions									
SO2 Emissions		71	71	72	73	73	74	75	67
Allowances Granted	70,211	88,554	63,139	63,139	63,139	63,139	63,139	63,139	63,139
Inventory		16,564	(62,498)	(80,495)	(81,943)	(83,405)	(85,234)	(87,064)	(71,139)
Shortfall			(62,498)	(80,495)	(81,943)	(83,405)	(85,234)	(87,064)	(71,139)
Allowance Price			186 03	196.26	207 06	218.44	230.46	243.13	256.51
2x SO2 Emissions		142	142	144	145	147	148	150	134

Cash Flow Data	2007	2008	2009	2010	2011	2012	2013	2014	2015
Revenues									
GWH Generation	16,179	15,957	15,739	15,524	15,092	14,672	14,264	13,868	13,482
AEP Price	28.39	29.22	30 08	30.96	31.81	32 69	33 60	34.53	35.48
PROSYM Revenues	486,251	494,558	503,006	511,600	511,972	512,346	512,719	513,093	513,467
Expenses									
O&M	77,772	80,812	83,971	87,254	87,107	86,961	86,815	86,669	86,523
Fuel Expense	197,648	201,110	204,633	208,238	204,507	200,863	197,283	193,767	190,314
Emissions									
SO2 Emissions	60	54	48	43	40	37	34	31	29
Allowances Granted	63,139	63,139	63,139	59,942	59,942	59,942	59,942	59,942	59,942
Inventory	(56,903)	(44,177)	(32,799)	(25,825)	(19,292)	(13,257)	(7,682)	(2,531)	2,228
Shortfall	(56,903)	(44,177)	(32,799)	(25,825)	(19,292)	(13,257)	(7,682)	(2,531)	-
Allowance Price	270 61	285.50	301.20	317 77	335 24	353.68	373.13	393.66	415.31
2x SO2 Emissions	120	107	96	86	79	73	68	62	58

1999 Depreciation and Investment

A&G Expense	52,891
Depreciation - Steam Gen	49,373
- Hydro	-
Gross Plant in Service - Steam Gen	1,542,898
- Hydro	-
Accum. Depreciation - Steam Gen	589,323
- Hydro	-
Net Plant	953,575

Plus Fuel Inventory	22,140
Plus M&S & Prepayments	18,000
Less Accum DFIT	10,840
Net Investment	1,004,555

NPV after Year 2015

Years for Straight Line Decay	15

Year	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Percentage Decayed	0%	6.67%	13.33%	20.00%	26.67%	33.33%	40.00%	46.67%	53.33%	60.00%	66.67%
Remaining value	$85,760	$80,043	$74,326	$68,608	$62,891	$57,173	$51,456	$45,739	$40,021	$34,304	$28,587

Year	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Percentage Decayed	73.33%	80.00%	86.67%	93.33%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Remaining value	$22,869	$17,152	$11,435	$5,717	$0	$0	$0	$0	$0	$0

NPV After Year 2015	$79,210

Cash Flow Data		1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Revenues																		
GWH Generation		0	48,624	48,912	49,009	49,350	49,637	50,085	48,162	46,315	44,538	42,830	41,187	40,919	40,651	40,386	40,122	39,860
AEP Price		0	23.62	23.76	24.01	24.26	25.53	26.79	27.58	28.39	29.22	30.08	30.96	31.81	32.69	33.60	34.53	35.48
PROSYM Revenue		0	1,228,139	1,246,894	1,265,936	1,285,269	1,368,680	1,462,091	1,438,367	1,424,772	1,411,307	1,397,964	1,384,756	1,409,979	1,435,662	1,461,812	1,468,439	1,515,950
Expenses																		
O&M		0	248,453	255,161	265,394	275,000	289,321	302,833	306,582	310,376	314,218	318,107	322,046	334,498	347,432	360,867	374,821	389,315
Fuel Expense		0	640,926	615,424	588,183	562,149	576,634	591,119	583,076	575,142	567,317	559,598	551,984	555,312	558,661	562,029	565,418	568,827
Emissions																		
SO2 Emissions		207	207	196	186	177	172	168	152	138	125	114	103	102	101	100	99	98
Allowances Granted	118,043	458,248	231,975	231,975	231,975	231,975	231,975	231,975	231,975	231,975	231,975	231,975	230,385	230,385	230,385	230,385	230,385	230,385
Inventory		232,037	49,758	(111,056)	(140,463)	(121,165)	(112,664)	(104,163)	(72,807)	(64,379)	(18,596)	4,778	29,161	55,415	83,524	113,470	145,236	178,811
Shortfall			-	(111,056)	(140,463)	(121,165)	(112,664)	(104,163)	(72,807)	(64,379)	(18,596)		-	-	-	-	-	-
Allowance Price			186.03	196.36	207.06	218.44	230.46	243.13	256.51	270.61	285.50	301.20	-	-	-	-	-	-
2x SO2 Emissions		414	414	393	372	353	345	336	305	276	251	227	206	204	202	200	199	197
Retirement as % of Generation											0.14		0.03					

WP-EXHIBIT NO. ____ JHL-2
(Page 2)

1999 Depreciation and Investment

A&G Expense	99,860
Depreciation - Steam Gen	89,337
- Hydro	2,962
Gross Plant in Service - Steam Gen	2,627,551
- Hydro	109,703
Accum. Depreciation - Steam Gen	1,505,142
- Hydro	41,388
Net Plant	1,190,724

Plus Fuel Inventory	92,929
Plus M&S & Prepayments	38,000
Less Accum DFIT	25,647
Net Investment	1,347,300

NPV after Year 2015

Years for Straight Line Decay	15

Year	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Percentage Decayed	0%	6.67%	13.33%	20.00%	26.67%	33.33%	40.00%	46.67%	53.33%	60.00%	66.67%	73.33%	80.00%	86.67%	93.33%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Remaining value	$208,437	$194,541	$180,645	$166,750	$152,854	$138,958	$125,062	$111,166	$97,271	$83,375	$69,479	$55,583	$41,687	$27,792	$13,896	$0	$0	$0	$0	$0	$0

NPV After Year 2015	$203,210

Cash Flow Data		1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Revenues																		
GWH Generation		•	16,238	16,400	16,564	16,730	16,893	17,056	16,739	16,427	16,121	15,821	15,526	15,328	15,132	14,939	14,748	14,560
AEP Price		•	23.52	24.64	25.81	27.04	28.64	30.23	30.83	31.44	32.06	32.70	33.34	34.34	35.36	36.41	37.49	38.60
PROSYM Revenues		•	396,780	421,730	448,249	476,435	507,138	537,841	537,082	536,324	535,568	534,812	534,857	541,583	549,214	556,953	564,801	572,768
Expenses																		
O&M		•	59,059	61,292	63,610	66,016	69,463	72,911	78,075	83,605	89,527	95,868	102,658	105,224	107,854	110,550	113,313	116,145
Fuel Expense		•	179,910	181,510	183,124	184,753	190,264	195,776	196,692	197,613	198,539	199,468	200,402	200,756	201,110	201,465	201,821	202,177
Emissions																		
SO2 Emissions		71	71	72	73	75	76	78	68	59	51	44	38	37	35	34	32	31
Allowances Granted	70,211	88,554	63,139	63,139	63,139	63,139	63,139	63,139	63,139	63,139	63,139	63,139	59,942	59,942	59,942	59,942	59,942	59,942
Inventory		16,564	9,492	(71,948)	(83,858)	(23,177)	(89,780)	(30,104)	(72,349)	(54,247)	(38,564)	(24,976)	46,739	33,510	23,321	16,045	11,562	58,135
Shortfall			-	(71,948)	(83,858)	(23,177)	(89,780)	(30,104)	(72,349)	(54,247)	(38,564)	(24,976)	-	-	-	-	-	-
Allowance Price			186.03	196.26	207.06	218.44	230.46	243.13	256.51	270.61	285.50	301.20	317.77	335.24	353.68	373.13	393.66	415.31
2x SO2 Emissions		142	142	145	147	149	153	156	135	117	102	88	76	73	70	67	64	62

1999 Depreciation and Investment	
A&G Expense	52,891
Depreciation - Steam Gen	49,373
- Hydro	-
Gross Plant in Service - Steam Gen	1,542,898
- Hydro	-
Accum. Depreciation - Steam Gen	589,323
- Hydro	-
Net Plant	953,575

Plus Fuel Inventory	22,140
Plus M&S & Prepayments	18,000
Less Accum DFIT	10,840
Net Investment	1,004,555

NPV after Year 2015

Years for Straight Line Decay	15

Year	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Percentage Decayed	0%	6.67%	13.33%	20.00%	26.67%	33.33%	40.00%	46.67%	53.33%	60.00%	66.67%
Remaining value	$105,146	$98,136	$91,126	$84,117	$77,107	$70,097	$63,087	$56,078	$49,068	$42,058	$35,049

Year	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Percentage Decayed	73.33%	80.00%	86.67%	93.33%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Remaining value	$28,039	$21,029	$14,019	$7,010	$0	$0	$0	$0	$0	$0

NPV After Year 2015	$97,115

WP-EXHIBIT NO. ____ JHL-2
(Page 4)

Cash Flow Data		1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Revenues																		
GWH Generation		0	48,634	49,408	50,204	51,812	51,497	52,982	50,698	49,446	48,225	47,034	45,873	45,950	46,027	46,104	46,182	46,259
AEP Price		0	23.52	24.64	25.81	27.04	28.64	30.23	30.83	31.44	32.06	32.70	33.34	34.34	35.36	36.41	37.49	38.60
PROSYM Revenues		0	1,238,199	1,308,845	1,394,855	1,486,517	1,590,490	1,696,463	1,863,511	1,633,124	1,603,293	1,574,036	1,545,256	1,593,268	1,642,773	1,693,816	1,746,445	1,800,709
Expenses																		
O&M		0	245,453	255,965	264,928	278,360	292,075	306,798	319,683	334,206	349,300	365,263	381,867	399,555	418,072	437,448	457,722	478,936
Fuel Expense		0	645,926	622,064	600,945	580,543	595,752	610,961	608,725	606,496	604,276	602,064	599,860	609,940	620,188	630,610	641,206	651,980
Emissions																		
SO2 Emissions		207	207	199	191	183	179	175	160	146	133	122	111	111	112	112	112	113
Allowances	188,043	458,248	231,975	231,975	231,975	231,975	231,975	231,975	231,975	231,975	231,975	231,975	230,385	230,385	230,385	230,385	230,385	230,385
Inventory		232,037	49,758	(116,084)	(150,058)	(134,904)	(126,240)	(117,580)	(87,343)	(59,721)	(34,489)	(11,440)	8,026	15,419	22,177	28,399	33,782	38,626
Shortfall			-	(116,084)	(150,058)	(134,904)	(126,240)	(117,580)	(87,343)	(59,721)	(34,489)	(11,440)	-	-	-	-	-	-
Allowance Price			186.03	196.26	207.06	218.44	230.46	243.13	256.51	270.61	285.50	301.20	317.77	335.24	353.68	373.13	393.66	415.31
2x SO2 Emissions		414	414	398	382	367	358	350	319	292	266	243	222	223	224	224	225	226
Retirements											0.14		-					

1999 Depreciation and Investment	
A&G Expense	99,860
Depreciation - Steam Gen	89,337
- Hydro	2,962
Gross Plant in Service - Steam Gen	2,627,551
- Hydro	109,703
Accum. Depreciation - Steam Gen	1,505,142
- Hydro	41,388
Net Plant	1,190,724
Plus Fuel Inventory	92,929
Plus M&S & Prepayments	38,000
Less Accum DFIT	25,647
Net Investment	1,347,300

NPV after Year 2015

Years for Straight Line Decay	15

Year	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Percentage Decayed	0%	6.67%	13.33%	20.00%	26.67%	33.33%	40.00%	46.67%	53.33%	60.00%	66.67%
Remaining value	$316,763	$295,646	$274,528	$253,411	$232,293	$211,176	$190,058	$168,940	$147,823	$126,705	$105,588

Year	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Percentage Decayed	73.33%	80.00%	86.67%	93.33%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Remaining value	$84,470	$63,353	$42,235	$21,118	$0	$0	$0	$0	$0	$0

NPV After Year 2015	$308,820

EXHIBIT NO.________

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Columbus Southern Power Company for Approval of Electric Transition Plan and Application for Receipt of Transition Revenues	Case No. 99-__-EL-ETP
In the Matter of the Application of Ohio Power Company for Approval of Electric Transition Plan and Application for Receipt of Transition Revenues	Case No. 99-__-EL-ETP

DIRECT TESTIMONY OF
JOHN M. MCMANUS
ON BEHALF OF
COLUMBUS SOUTHERN POWER COMPANY
AND
OHIO POWER COMPANY

INDEX TO DIRECT TESTIMONY OF
JOHN M. MCMANUS
PUCO CASE NOS. 99-___-EL-ETP and
99-___-EL-ETP

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BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO
DIRECT TESTIMONY OF
JOHN M. MCMANUS
ON BEHALF OF
COLUMBUS SOUTHERN POWER COMPANY
CASE NO. 99-___-EL-ETP
AND
OHIO POWER COMPANY
CASE NO. 99-___-EL-ETP

Personal Data

Q. Please state your name and business address.

A. My name is John M. McManus. My business address is 1 Riverside Plaza, Columbus, Ohio 43215.

Q. Please indicate by whom you are employed and in what capacity.

A. I am the Manager of Environmental Strategy and Planning for American Electric Power Service Corporation (AEPSC), a wholly owned subsidiary of American Electric Power Company, Inc. (AEP) the parent of Columbus Southern Power Company (CSP) and Ohio Power Company (OPCO).

Q. Please briefly describe your educational background and business experience.

A. I earned a Bachelor of Science Degree in Environmental Engineering from Rensselaer Polytechnic Institute in 1976 and undertook graduate studies at the same location from 1976-77. I joined the AEPSC Environmental Engineering Division in September, 1977. After holding various positions in the environmental division over the years, I was appointed to my current position in January, 1997. In that position, I am responsible for overseeing AEP's compliance with Title IV of the Clean Air Act Amendments of 1990 and for evaluating the potential for future legislative and regulatory environmental initiatives that could result in new emission control requirements for Company facilities. I am a licensed Professional Engineer in the State of Ohio.

Purpose of Testimony

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to describe potential future environmental regulatory programs that could affect coal-fired generating plants in general, and would result in significant cost exposure to OPCO's and CSP's coal-fired power plants. This information has been provided to Company Witness Landon for his use in his analysis. I am also sponsoring the CSP and OPCO actual emission allowance balances at December 31, 1998 and 1999, and the projected CSP and OPCO emission allowance balances at December 31, 2000 as shown in the Company's Response to Part F, §(B)(1)(b)(iv)(d).

Future Regulatory Exposure for Nitrogen Oxides

Q. Do CSP and OPCO have emission control requirements for nitrogen oxides (NOx)?

A. Both CSP and OPCO coal-fired plants must comply with the NOx requirements of Title IV. Certain units have had a NOx emission limit since 1996, and beginning in the year 2000, all coal-fired units must meet applicable NOx limits. These limits can be met using combustion technology such as low NOx burners or their equivalent. It is anticipated at this time that all units will be able to meet compliance requirements for 2000.

Q. Do these facilities face additional NOx control requirements beyond Title IV?

A. Yes. In November, 1997, the U.S. Environmental Protection Agency (USEPA) proposed a broad-ranging NOx control program to address ozone air quality problems in the eastern U.S. That program would have required reductions in NOx emissions from CSP and OPCO plants during the months of May to September that cannot be met with the control technology being used to meet Title IV limits. Instead, extensive use of post-combustion control technology such as selective non-catalytic reduction (SNCR) and selective catalytic reduction (SCR) technology would be required. The State of Ohio, working in concert with a number of other Midwestern and Southeastern states, proposed an alternative NOx control program that, while calling for less stringent NOx control levels, would still result in application of SNCR and SCR technology. USEPA's proposal has been described as an 85% NOx reduction program, while the Ohio alternative calls for roughly 65% reduction in NOx emissions. Ohio and other states have legally challenged USEPA's program. A decision on that appeal is not expected until the Spring of 2000.

Q. Given the uncertainty surrounding USEPA's proposed program, do the CSP and OPCO coal-fired facilities face significant cost exposure for future NOx control requirements?

A. Yes. Even if Ohio's appeal of USEPA's program is upheld, it is expected that Ohio and surrounding states, including West Virginia, where some OPCO facilities are located, will implement a NOx control program at the 65% reduction level and possibly slightly more restrictive. The compliance deadline in USEPA's program would have been May, 2003. The delay in implementation that has occurred with the appeal raises serious questions as to the viability of meeting this deadline, with a delay until May, 2005 a possibility. The Ohio 65% reduction alternative program included a May, 2004 compliance deadline. Given the more reasonable reduction level, this deadline may still be viable.

Future Regulatory Exposure for Sulfur Dioxide

Q. Do CSP and OPCO have emission control requirements for sulfur dioxide (SO_2)?

A. Yes. The CSP and OPCO coal-fired units have specific SO_2 emission limits that have been in place since the 1970s. In addition, these units are governed by the SO_2 allowance program in Title IV. Almost all of the Companies' units are in Phase I of the Title IV program, which began in 1995, with the remaining units in Phase II, which begins in 2000. CSP and OPCO Phase I units have complied with Title IV allowance limits through a combination of SO_2 control technology, fuel switches and allowance transfers. No additional SO_2 control technology retrofits are planned at this time for Phase II. Instead, a combination of fuel switches and utilization of banked or procured allowances will be used to achieve compliance in the most cost-effective manner.

Q. Do these facilities face additional SO_2 control requirements beyond Title IV?

A. Possibly. In June, 1997, USEPA promulgated a new fine particulate air quality standard. That standard, referred to as $PM_{2.5}$, could result in additional SO_2 control requirements for CSP and OPCO units that are determined to contribute to nonattainment of the standard. While it will be a number of years before there is actual air quality data suitable for determining if these units do contribute to a $PM_{2.5}$ air quality problem, USEPA has publicly stated its belief that SO_2 emissions from coal-fired power plants in general will have to be reduced by 50-60% below the Title IV Phase II allowance allocation level in order for the $PM_{2.5}$ standard to be attained. While there is no question that SO_2 emissions from coal-fired plants can contribute to fine particulate sulfate, USEPA's conjecture on an appropriate control level is based on very limited data. As actual $PM_{2.5}$ air quality data is collected, it will be possible to more accurately quantify the contribution of CSP and OPCO facilities. USEPA also recently promulgated a regulation to address regional haze. To the extent that SO_2 emissions from coal-fired units contribute to regional haze, this new rule could also result in additional SO_2 control requirements for CSP and OPCO facilities.

Q. When might CSP and OPCO facilities face additional SO_2 control requirements?

A. The new $PM_{2.5}$ standard was legally challenged and remanded to USEPA. USEPA appealed that decision and was turned down. The Agency has indicated its intention to appeal further to the U.S. Supreme Court. The result is likely to be a significant delay in implementation of the new standard and a question as to the ultimate level and form of the standard. It is reasonable to assume that additional SO_2 control requirements for the $PM_{2.5}$ air quality standard or the regional haze rule will not apply until 2010.

Future Regulatory Exposure for Carbon Dioxide

Q. Do CSP and OPCO have emission control requirements for carbon dioxide (CO_2)?

A. No. There are currently no emission control requirements for CO_2. While the Clinton Administration has signed the Kyoto Protocol, that protocol has not been ratified by the U.S. Senate. The Protocol would require the U.S. to limit its emissions of greenhouse gases (GHGs) to 7% below 1990 levels beginning in a 2008-12 budget period. The Senate is unlikely to ratify the Kyoto Protocol in its current form, but it has considered legislation that would provide incentives for voluntary efforts to reduce GHG emissions, including CO_2. While mandatory targets and timetables for GHGs are unlikely to apply in the next ten years, a voluntary program or some form of a nominal carbon emissions tax might be implemented.

U.S. EPA Enforcement Action

Q. What are the implications of the recently announced enforcement action by the U.S. Department of Justice (USDOJ) and USEPA?

A. On November 3, 1999 the USDOJ announced its intent to commence legal action against certain electric utility companies and USEPA issued Notices of Violation for certain coal-fired power plants. Facilities of CSP and OPCO are included in this action. It is not clear at this time what the ultimate outcome of this action will be. CSP and OPCO believe that Company facilities have been operated in full compliance with the requirements of the Clean Air Act. If USDOJ and USEPA prevail in this action, CSP and OPCO coal-fired units may have to install additional emission control technology such as flue gas desulfurization systems and SCR technology.

Potential Emission Control Requirements

Q. What emission control requirements might CSP and OPCO facilities face in the coming years?

A. If the states of Ohio and West Virginia proceed with a 65% NOx reduction program, then 900 MW of CSP generation and 6,900 MW of OPCO generation may have to be retrofit with NOx control technology by May, 2004. In the event that USEPA prevails with its 85% reduction proposal, then the amount of generation affected increases to 2,600 MW for CSP and 8,500 MW for OPCO by May, 2005. It is not clear how any additional SO_2 reduction requirements would be implemented. It is possible that any additional control programs for $PM_{2.5}$ or regional haze will rely on the existing SO_2 allowance program as the basis for emission reductions, but with a reduction in the number of allowances allocated to generating units. However, additional regulatory requirements might also target specific units for the installation of SO_2 control technology. Successful prosecution by USDOJ and USEPA of its enforcement initiative could lead to unit-specific requirements to install SO_2 and NOx control technology. Finally, some form of a CO_2 limitation program may be in place in the next ten years. Even given the uncertainty surrounding these environmental programs, it is apparent that the coal-fired units of CSP and OPCO face considerable cost exposure in the future.

Q. Does this conclude your testimony?

A. Yes.

EXHIBIT NO.________

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Columbus Southern Power Company for Approval of Electric Transition Plan and Application for Receipt of Transition Revenues	Case No. 99-__-EL-ETP
In the Matter of the Application of Ohio Power Company for Approval of Electric Transition Plan and Application for Receipt of Transition Revenues	Case No. 99-__-EL-ETP

DIRECT TESTIMONY OF
OLIVER J. SEVER, JR.
ON BEHALF OF
COLUMBUS SOUTHERN POWER COMPANY
AND
OHIO POWER COMPANY

INDEX TO DIRECT TESTIMONY OF
OLIVER J. SEVER, JR.
PUCO CASE NOS. 99-___-EL-ETP and
99-___-EL-ETP

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BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO
DIRECT TESTIMONY OF
OLIVER J. SEVER, JR.
ON BEHALF OF
COLUMBUS SOUTHERN POWER COMPANY
CASE NO. 99-___-EL-ETP
AND
OHIO POWER COMPANY
CASE NO. 99-___-EL-ETP

Personal Data

Q. Please state your name and business address.

A. My name is Oliver J. Sever, Jr., and my business address is 1 Riverside Plaza, Columbus, Ohio 43215.

Q. By whom are you employed and what is your position?

A. I am employed by the American Electric Power Service Corporation (AEPSC) as Director of Financial Planning and Forecasting. AEPSC supplies engineering, financing, accounting and similar planning and advisory services to the seven electric operating companies of the American Electric Power (AEP) System.

Q. Briefly describe your educational and professional background.

A. I received a Bachelor of Science Degree in Business Administration from The Ohio State University in 1979, and a Masters of Business Administration from The University of Dayton in 1983. In addition, I completed The Darden Partnership Program at the Darden Graduate School of Business Administration, University of Virginia, in February 1997.

After working in the Controllers Division of a nonaffiliated utility for the period 1979 to 1983, I joined the AEPSC in 1983 as an Assistant Financial Analyst in the

Controllers Department (now Corporate Planning and Budgeting Department), was promoted to Financial Analyst in June 1984, Senior Financial Analyst in January 1987, Senior Administrative Assistant II in January 1990, Senior Administrative Assistant I in January 1992, Manager, Financial Planning and Forecasting in April 1992 and I assumed my present position in January 1998.

Q. What are your responsibilities as Director of Financial Planning and Forecasting?

A. I am responsible for the supervision and administration of financial planning and budgeting processes for the AEP System. In such capacity I coordinate utilization of short- and long-term financial planning models used in the development of operating and capital budget forecasts for the AEP System and review the preparation of forecasted information for use in regulatory proceedings.

Q. Have you previously submitted testimony as a witness before a regulatory commission?

A. Yes. I have testified on behalf of the Ohio Power Company before the Public Utilities Commission of Ohio. Also, I have offered testimony on behalf of Indiana Michigan Power Company before the Indiana Utility Regulatory Commission and in front of the Michigan Public Service Commission. In addition, I have testified for Appalachian Power Company before the Public Service Commission of West Virginia and the Virginia State Corporation Commission. I have also testified before the Federal Energy Regulatory Commission.

Purpose of Testimony

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to present data used for, and the methodologies employed in developing financial forecasts for Columbus Southern Power Company (CSP) and Ohio Power Company (OPCO). These forecasts provide a basis from which financial forecasts for a generating company operating in a deregulated market may be developed.

List of Exhibits

Q. What exhibits are you sponsoring in this proceeding?

A. I am sponsoring the following exhibits for CSP and OPCO:

Description:

1. EXHIBIT NO. ___ OJS-1, AEP System Fixed and Variable Operations and Maintenance Expense and Rates.
2. EXHIBIT NO. ___ OJS-2, AEP System Fuel Rates (cents/mBtu) 2000-2015.
3. EXHIBIT NO. ___ OJS-3, CSP and OPCO Capital Expenditures 2000-2009 (incl. AFUDC, excl. environ. compliance).
4. EXHIBIT NO. ___ OJS-4, AEP System 65% NO_x Investment Schedule – Capital.
5. EXHIBIT NO. ___ OJS-5, OPCO and CSP Stranded Cost Model Input Data.

Q. Were the exhibits you are sponsoring prepared by you or under your supervision?

A. Yes. Various people prepared the data and I am familiar with the methods used in its development.

Q. How is the information in your exhibits used in this proceeding?

A. This information was provided to Company Witness Landon, who is preparing and sponsoring CSP's and OPCO's stranded cost estimates. See Part F, §(B)(2)(b) and (C)(1).

Discussion of Forecasted Data and Forecast Methodologies

Q. What type of information did you provide Company Witness Landon?

A. I provided Company Witness Landon the following data:

- 1998 year-end financial information such as gross plant and accumulated depreciation.
- Projections of Operations and Maintenance (O&M) Expense, Fuel Costs, Administrative and General Expenses, Other Tax Expense, Capital Investment estimates, Decommissioning Cost estimates, and Schedule M estimates.
- SO_2 allowance allocations and inventory data.
- NO_x investment data.
- Forecasted financial statements from CSP's and OPCO's 1999 approved budget.

Q. Would you please describe how operations and maintenance expenses were estimated?

A. Yes. The O&M forecast consists of a fixed and a variable component. The fixed component is estimated based on a historical relationship whereby Non-fuel

Operations Expense is added to one half of the Maintenance Expense. This base level is adjusted for special items such as leases and decommissioning costs that would not be escalated or have a different escalation rate. After the necessary adjustments an annual escalation rate of 2.5% is applied to yield fixed O&M expense. The fixed component is then allocated to each station based on generation capacity. The variable rate component is estimated by dividing one half of the Maintenance Expense by the generation to produce a rate that is escalated 2.5% annually and applied to future generation projections to determine a variable cost. Data used to determine the variable component is from actual 1998 annual results, adjusted for any unusual events, such as outages.

Q. Would you please describe how the cost of fossil fuel consumed was calculated?

A. Yes. AEP's Fuel Supply Department projects a weighted-average fuel cost rate (in cents per million BTU) which incorporates coal contracts, and spot market fuel cost rates by coal pile. Additional costs such as fuel handling, which is based on historical data, and scrubber costs are added to this rate in the appropriate years. Adjustments to this rate are made to remove the effects of mine shutdown costs and include the benefits of Ohio Coal Tax credits.

Q. Would you please describe how capital expenditures were estimated?

A. Yes. Capital expenditure data is based on the 2000 five-year capital budget target. After the five-year period an assumed 2.5% growth rate/year in baseline expenditures (over the prior year) is applied through 2009. The General portion of capital expenditure is allocated to generation based on gross plant percentage. Total capital expenditure estimates are reduced in proportion to the amount of generation capacity lost when decommissionings occur. Also, for units decommissioned during the period of the study, an estimate of the capital expenditures to be written off was made based on the given plant's net book value at the time of decommissioning. The estimate assumed a reduction of capital expenditure in the years immediately prior to decommissioning.

Q. Would you please describe how administrative and general expenses were developed and projected?

A. Yes. As defined by the FERC Chart of Accounts, this analysis includes administrative and general (A&G) expense, customer service and customer accounting expenses. The 1998 actual amounts were allocated to generation based on gross plant and escalated 2.5% annually.

Q. Would you please describe how "Other Taxes" were estimated and projected for a generating company in a deregulated market?

A. Yes. The "Other Taxes" line item incorporates year 2000 forecast inputs for Property tax, West Virginia State Income tax, West Virginia B&O tax, Payroll Taxes, and Other Items. These pieces are each escalated at varying rates based on historical data. The Property tax estimates are reduced to 25% in 2002 in accordance with the Ohio deregulation legislation.

Q. Would you please describe how Schedule M data was estimated?

A. Yes. Schedule M data is estimated by using historic values to predict schedule M component amounts for the following year. Each component is small and may vary year to year without appreciably changing the total Schedule M amount. Because of this, Schedule M amounts are held constant for each company. For CSP, a component of the Schedule M is related to gross receipts tax and is removed from the estimate in 2001 and beyond.

Q. Does this conclude your testimony?

A. Yes.

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AEP System Fixed and Variable Operations and Maintenance Expense and Rates

PLANT	1999 Forecast Fixed O&M ($000)	1/98 - 12/98 Variable O&M (M/Kwh)*
Amos 1	9,799	
Amos 2	9,799	
Amos 3	15,923	
Beckjord	992	
Big Sandy 1	3,043	
Big Sandy 2	9,365	
Cardinal 1	8,696	
Clinch River 1	2,654	
Clinch River 2	2,654	
Clinch River 3	2,654	
Conesville 1	2,340	
Conesville 2	2,340	* [REDACTED DATA FILED
Conesville 3	3,088	UNDER SEAL WITH THE
Conesville 4	6,345	COMMISSION]
Conesville 5	7,019	
Gavin 1	37681	
Gavin 2	57,672	
Glen Lyn 5	1,073	
Glen Lyn 6	2,710	
Kammer 1	3,043	
Kammer 2	3,043	
Kammer 3	3,043	
Kanawha River 1	2,258	
Kanawha River 2	2,258	
Mitchell 1	11,594	
Mitchell 2	11,594	
Mountaineer	14,679	
Muskingum 1	2,971	
Muskingum 2	2,971	
Muskingum 3	3,116	
Muskingum 4	3,116	
Muskingum 5	8,478	
Pickway 5	1,872	
Rockport 1	27,656	
Rockport 2	138,430	
Sporn 1	2,037	
Sporn 2	2,037	
Sporn 3	2,037	
Sporn 4	2,037	
Sporn 5	6,110	
Stuart 1	2,845	
Stuart 2	2,845	
Stuart 3	2,845	
Stuart 4	2,845	
Tanners Creek 1	1,887	
Tanners Creek 2	1,887	
Tanners Creek 3	2,668	
Tanners Creek 4	6,508	
Zimmer	6,177	

AEP System Fuel Rates (cents/mBtu) 2000 - 2015

NOTE: Mine shut down costs are excluded in rates shown.

PLANT	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Amos																
Big Sandy																
Cardinal 1																
Cardinal 2,3																
Clinch River																
Conesville 1,2,3																
Conesville 4																
Conesville 5,6																
Gavin																
Glen Lyn																
Kammer																
Kanawha River																
Mitchell																
Mountaineer																
Muskingum 1,2,3,4																
Muskingum 5																
Pickway																
Rockport																
Sporn																
Tanners Creek 1,2,3																
Tanners Creek 4																

[REDACTED DATA FILED UNDER SEAL WITH THE COMMISSION]

CSP and OPCO Capital Expenditures 2000 - 2009 (incl. AFUDC, excl. environ. compliance)

(in $000)

NOTE: (1) For years 2004-2009 assume base level functional allocation based on 1999 - 2003.
(2) For years 2004-2009, assume 2.5% growth rate/yr in baseline expenditures over the prior year.
(3) The GENERAL amount represents 59.5% of total OPCO and 54.43% of total CSP amounts based on gross plant %.

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
COLUMBUS SOUTHERN POWER										
MAJOR GENERATION	0	0	0	0	0	0	0	0	0	0
ENVIRONMENTAL	9,251	16,380	392	1,768	870	892	914	937	960	984
OTHER PRODUCTION	15,038	13,724	17,228	29,054	14,892	15,264	15,646	16,037	16,438	16,849
GENERAL	7,654	7,693	7,712	7,683	7,836	8,032	8,233	8,439	8,650	8,866
OTHER INVESTMENTS	0	0	0	0	0	0	0	0	0	0
TOTAL	31,943	37,796	25,332	38,503	23,598	24,188	24,793	25,413	26,048	26,699

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
OHIO POWER										
MAJOR GENERATION	0	0	0	0	0	0	0	0	0	0
ENVIRON.	5,782	4,241	238	8,120	4,000	4,100	4,203	4,308	4,415	4,526
OTHER PRODUCTION	73,584	82,052	71,540	40,150	78,928	80,901	82,923	84,996	87,121	89,299
GENERAL	8,082	8,123	8,144	8,113	8,275	8,482	8,694	8,912	9,134	9,363
UNASSIGNED (Cook Coal Term)	455	155	195	800	816	836	857	879	901	923
OTHER INVESTMENTS/Coal Cos.	9,832	7,995	0	0	0	0	0	0	0	0
TOTAL	97,735	102,566	80,117	57,183	92,019	94,319	96,677	99,094	101,572	104,111

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AEP System 65% Nox Investment Schedule - Capital
(in $000)

UNIT	Technology	In Service Date	Total Capital	Capital Labor	Capital Material	2000	2001	2002	2003	2004	2005	2006	2007
Amos 1	SNCR	2,003	9,600	100%	0%	0	0	6,031	4,415	0	0	0	0
Amos 2	SNCR	2,003	9,600	100%	0%	0	0	6,031	4,415	0	0	0	0
Amos 3	SCR	2,002	100,100	43%	57%	0	61,348	44,915	0	0	0	0	0
Beckjord 6	Do Nothing	0	0	0%	0%	0	0	0	0	0	0	0	0
Big Sandy 1	Do Nothing	0	0	0%	0%	0	0	0	0	0	0	0	0
Big Sandy 2	SNCR	2,005	9,600	100%	0%	0	0	0	0	6,336	4,639	0	0
Cardinal 1	SNCR	2,003	1	100%	0%	0	0	0	0	0	0	0	0
Clinch R 1	SNCR	2,003	3,760	100%	0%	0	0	2,362	1,729	0	0	0	0
Clinch R 2	SNCR	2,003	3,760	100%	0%	0	0	2,362	1,729	0	0	0	0
Clinch R 3	SNCR	2,003	3,760	100%	0%	0	0	2,362	1,729	0	0	0	0
Conesville 1	Do Nothing	0	0	0%	0%	0	0	0	0	0	0	0	0
Conesville 2	Do Nothing	0	0	0%	0%	0	0	0	0	0	0	0	0
Conesville 3	Do Nothing	0	0	0%	0%	0	0	0	0	0	0	0	0
Conesville 4	Do Nothing	2,003	0	0%	0%	0	0	0	0	0	0	0	0
Conesville 5	Do Nothing	0	0	0%	0%	0	0	0	0	0	0	0	0
Conesville 6	Do Nothing	0	0	0%	0%	0	0	0	0	0	0	0	0
Gavin 1	SCR	2,002	94,900	43%	57%	0	58,161	42,582	0	0	0	0	0
Gavin 2	SCR	2,002	94,900	43%	57%	0	58,161	42,582	0	0	0	0	0
Glen Lyn 5	Do Nothing	0	0	0%	0%	0	0	0	0	0	0	0	0
Glen Lyn 6	Do Nothing	0	0	0%	0%	0	0	0	0	0	0	0	0
Kammer 1	Do Nothing	0	0	0%	0%	0	0	0	0	0	0	0	0
Kammer 2	Do Nothing	0	0	0%	0%	0	0	0	0	0	0	0	0
Kammer 3	Do Nothing	0	0	0%	0%	0	0	0	0	0	0	0	0
Kanawha 1	SNCR	2,003	3,200	100%	0%	0	0	2,010	1,472	0	0	0	0
Kanawha 2	SNCR	2,003	3,200	100%	0%	0	0	2,010	1,472	0	0	0	0
Mitchell 1	SNCR	2,004	9,600	100%	0%	0	0	0	6,181	4,526	0	0	0
Mitchell 2	SNCR	2,005	9,600	100%	0%	0	0	0	0	6,336	4,639	0	0
Mountaineer	SNCR	2,003	15,600	100%	0%	0	0	9,800	7,175	0	0	0	0
Muskingum 1	SNCR	2,003	3,280	100%	0%	0	0	2,060	1,509	0	0	0	0
Muskingum 2	Do Nothing	0	0	0%	0%	0	0	0	0	0	0	0	0
Muskingum 3	Do Nothing	0	0	0%	0%	0	0	0	0	0	0	0	0
Muskingum 4	Do Nothing	0	0	0%	0%	0	0	0	0	0	0	0	0
Muskingum 5	Gas Reburn	2,002	8,635	#N/A	#N/A	0	5,292	3,875	0	0	0	0	0
Picway 5	Do Nothing	0	0	0%	0%	0	0	0	0	0	0	0	0
Sporn 1	Do Nothing	0	0	0%	0%	0	0	0	0	0	0	0	0
Sporn 2	Do Nothing	0	0	0%	0%	0	0	0	0	0	0	0	0
Sporn 3	Do Nothing	0	0	0%	0%	0	0	0	0	0	0	0	0
Sporn 4	Do Nothing	0	0	0%	0%	0	0	0	0	0	0	0	0
Sporn 5	SNCR	2,003	5,400	100%	0%	0	0	3,392	2,484	0	0	0	0
Rockport 1	SNCR	2,003	26,000	100%	0%	0	0	16,333	11,958	0	0	0	0
Rockport 2	SNCR	2,005	26,000	100%	0%	0	0	0	0	17,160	12,563	0	0
Stuart 1	SCR	2,003	14,744	43%	57%	0	0	9,262	6,781	0	0	0	0
Stuart 2	SCR	2,003	14,744	43%	57%	0	0	9,262	6,781	0	0	0	0
Stuart 3	SCR	2,003	14,744	43%	57%	0	0	9,262	6,781	0	0	0	0
Stuart 4	SNCR	2,003	2,432	100%	0%	0	0	1,528	1,119	0	0	0	0
Tanners Ck 1	Do Nothing	0	0	0%	0%	0	0	0	0	0	0	0	0
Tanners Ck 2	Do Nothing	0	0	0%	0%	0	0	0	0	0	0	0	0
Tanners Ck 3	SNCR	2,003	3,280	100%	0%	0	0	2,060	1,509	0	0	0	0
Tanners Ck 4	PRB100_OFA_SNCF	2,003	43,131	100%	0%	0	0	27,094	19,837	0	0	0	0
Zimmer	SCR	2,003	23,760	43%	57%	0	0	14,926	10,928	0	0	0	0

Stuart, Zimmer assumed to be completed by spring 2003.

OPCO and CSP Stranded Cost Model Input Data

(in $000)

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OPCo

				1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
1)	A&G	Generation Specific		99,860	93,279	94,870	101,464	102,737	103,708	104,803	105,907	106,827	108,064	109,114						
2)	Depreciation																			
	Steam Gen		3.4%																	
	Hydro		2.7%																	
3)	Schedule M's			4,452	3,466	3,466	3,466	3,466	3,466	3,466	3,466	3,466	3,466	3,466						
4)	Tax Rates																			
	Combined Effective Rate		40.56%																	
5)	Leverage	Generation Specific																		
	Debt		40.00%																	
	Equity		60.00%																	
6)	Other Taxes	Generation Specific		77,672	78,147	78,829	42,536	42,851	43,172	43,500	43,836	44,177	44,527	44,884						
7)	Capital Expenditure	Generation Specific			97,735	102,566	90,117	57,183	92,019	94,319	96,677	81,891	83,939	82,352	84,411	86,521	88,684	90,901	93,174	95,503
8)	Write-Off Amounts												58,750		18,413					

CSP

				1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
1)	A&G			65,985	61,861	66,843	65,996	69,905	70,470	73,034	71,390	75,888	82,786	75,590						
2)	Depreciation																			
	Steam Gen		3.2%																	
	Transmission		2.3%																	
3)	Schedule M's			(2,378)	(2,866)	(463)	(463)	(463)	(463)	(463)	(463)	(463)	(463)	(463)						
4)	Tax Rates																			
	Combined Effective Rate		40.56%																	
5)	Leverage	Generation Specific																		
	Debt		40.00%																	
	Equity		60.00%																	
6)	Other Taxes	Generation Specific		40,645	41,106	42,707	13,663	14,163	14,679	15,216	15,774	16,351	16,950	17,573						
7)	Capital Expenditure	Generation Specific			31,943	37,796	26,332	38,503	23,596	24,186	24,793	25,413	26,048	26,699	27,367	23,723	24,316	24,924	24,579	25,193
8)	Write-Off Amounts																10,999			1,829

* NOTE: Capital Expenditure amounts are reduced in relation to the % of capacity decommissioned. This reduction is assumed to occur in the year prior to the decommissioning.

EXHIBIT NO.________

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Columbus Southern Power Company for Approval of Electric Transition Plan and Application for Receipt of Transition Revenues	Case No. 99-__-EL-ETP
In the Matter of the Application of Ohio Power Company for Approval of Electric Transition Plan and Application for Receipt of Transition Revenues	Case No. 99-__-EL-ETP

DIRECT TESTIMONY OF
LAURA J. THOMAS
ON BEHALF OF
COLUMBUS SOUTHERN POWER COMPANY
AND
OHIO POWER COMPANY

INDEX TO DIRECT TESTIMONY OF
LAURA J. THOMAS
PUCO CASE NOS. 99-___-EL-ETP and
99-___-EL-ETP

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3. Overview of Tariff Terms and Conditions of Service and Rate Schedules 3
4. Standard Tariff 4
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6. Overview of the Companies' Unbundling Approach 13
7. Rate Design 15
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BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO
DIRECT TESTIMONY OF
LAURA J. THOMAS
ON BEHALF OF
COLUMBUS SOUTHERN POWER COMPANY
CASE NO. 99-___-EL-ETP
AND
OHIO POWER COMPANY
CASE NO. 99-___-EL-ETP

Personal Data

Q. Please state your name and business address?

A. My name is Laura J. Thomas. My business address is 1 Riverside Plaza, Columbus, Ohio 43215.

Q. Please indicate by whom you are employed and in what capacity?

A. I am the Director of Pricing and Contracts for American Electric Power Service Corporation (AEPSC), a wholly owned subsidiary of American Electric Power Company, Inc. (AEP) the parent of Columbus Southern Power Company (CSP) and Ohio Power Company (OPCO).

Q. Please briefly describe your educational background and business experience?

A. In 1979 I received a Bachelor of Science degree in mathematics with a statistics minor from The Ohio State University. I also received a Master of Science degree in mathematics in 1981 while teaching undergraduate mathematics at The Ohio State University. I completed the AEP Management Development Program in 1996.

In 1982 I joined the AEPSC as an Assistant Rate Analyst. I was promoted to various levels of rate analyst and on January 1, 1996, I was promoted to my current position as Director – Pricing and Contracts. My responsibilities include the supervision of the preparation of class cost-of-service studies and rate design for the American Electric Power Company, Inc. operating companies, and special contracts and pricing for retail customers.

Q. Have you previously testified before any regulatory commissions?

A. Yes. I have testified on cost-of-service and rate design-related issues before regulatory commissions in the states of Indiana, Michigan, Ohio, Tennessee, Virginia and West Virginia and before the Federal Energy Regulatory Commission (FERC).

Purpose of Testimony

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to outline the overall approach to the Companies' proposed terms and conditions of service and rate schedule development, explain the unbundling methodology utilized by the Companies, and to sponsor portions of Parts A and F of the Companies' filings.

Q. What portions of Part A do you sponsor?

A. I sponsor the proposed terms and conditions of service and rate schedules as contained in Schedules UNB-1 and UNB-2 and I also sponsor the remainder of the Companies' response to Part A with the following exceptions:

1. Company Witness Forrester sponsors those portions related to the Universal Service Fund Rider and Energy Efficiency Fund Rider;

2. Company Witness Bethel sponsors those portions of Part A related to the AEP Open Access Transmission Tariff and the portion of Part A, §(F)(2)(g) as it relates to the FERC seven-factor test; and

3. Company Witness Roush sponsors the numbers and calculations as contained in Schedules UNB-3 through UNB-8.

Q. What portions of Part F do you sponsor?

A. I sponsor Part F, §F(1)(a) and §F(1)(b).

Overview of Tariff Terms and Conditions of Service and Rate Schedules

Q. Please describe the Companies' overall approach to the development of terms and conditions of service and rate schedules which comply with the unbundling criteria and other Commission requirements.

A. In order to present clear and understandable documents for use by both customers and other market participants, the Companies have taken a two-tariff approach. The first tariff applies to those customers who do not choose an alternative Electric Supplier and continue to take energy–related services from either of the regulated Companies during the Market Development Period. The first tariff will be referred to as the Standard Tariff.

The second tariff applies to those customers who choose an alternative Electric Supplier. While many of the provisions are the same regardless of whether it is a regulated or an unregulated entity which provides the customer with energy, some differentiation is necessary. The two-tariff approach makes it clear as to which provisions actually apply to the customer. The second tariff will be referred to as the Open Access Distribution Tariff.

Q. What corporate name appears on the various components of the Standard Tariff and the Open Access Distribution Tariff?

A. The components of the Standard Tariff and the Open Access Distribution Tariff indicate the names "Ohio Power Distribution Company" and "Columbus Southern Power Distribution Company."

Q. Please explain the basis for these names.

A. Consistent with the corporate separation plan sponsored by Company Witness Forrester, these names are used to indicate that the Standard Tariff and Open Access Distribution Tariff belong to the distribution entity. Because the Companies have not yet determined an official name for their distribution companies, these names are merely a placeholder to indicate the corporate entity providing distribution services.

Standard Tariff

Q. Please describe the Standard Tariff.

A. In Schedules UNB-1 and UNB-2, the Standard Tariff consists of Terms and Conditions of Service, rate schedules and riders which are generally comparable to those in effect today. However, they reflect the "Adjusted Unbundled Rates" as defined in Part A, §(B)(3) and as required by Am. Sub. S. B. No. 3. The rate schedules detail the generation, transmission and distribution components of existing rates and include the following riders: Universal Service Fund, Energy

Efficiency Fund, KWH Tax, Gross Receipts Tax Credit, Property Tax Credit, Municipal Income Tax, Franchise Tax and Regulatory Asset Charge. The Adjusted Unbundled Rates contained in the Standard Tariff exclude the effects of the riders listed above.

Q. During what period will be the Standard Tariff be in effect?

A. All components of the Standard Tariff (Terms and Conditions of Service, rate schedules including generation, transmission and distribution rate components, and the riders mentioned above) will remain in effect until no later than December 31, 2005 which is the anticipated termination of the Market Development Period. Should the Market Development Period terminate at an earlier date, then the components of the Standard Tariff would also terminate.

Q. Do the rate schedules contained in the Standard Tariff filed by each Company represent a standard service offer?

A. Yes. For the Market Development Period, the Companies are required to provide a standard offer for generation service "priced in accordance with the schedule containing the utility's unbundled generation service component" as specified in Am. Sub. S. B. No. 3, §4928.35(D). Because the rate schedules in the Standard Tariff reflect Adjusted Unbundled Rates, and therefore reflect the unbundled cost of generation, these rate schedules address the required standard offer for generation service. During the Market Development Period, customers who receive service from an alternative Electric Supplier may return to this standard offer. However, once returning to such service, the customer is required to take the standard offer for the remainder of the Market Development Period, or for 12 months, whichever is longer. This requirement is necessary to prevent gaming by Electric Suppliers and customers. After the Market Development Period, the standard offer for generation service must be market-based and is not further addressed in this filing.

Q. Please further explain the issue of gaming.

A. The generation rates contained in the Standard Tariff are historical average generation rates and therefore do not reflect any yearly, seasonal, or even monthly, differences in the cost to serve a customer who may take service for only a portion of one or more years. Therefore, gaming would occur if an Electric Supplier provides service to a customer only in periods of low cost. It would neither be equitable nor appropriate for an Electric Supplier to serve a customer for only low cost periods and then require the Company to serve the customer in the high cost periods at average rates. The standard offer for generation service is not intended to provide the customer with the lower of the Company's rates or market-based rates at every point during the Market Development Period. Instead, the standard offer for generation service is intended to provide an option for customers who choose to wait before selecting an alternative Electric Supplier.

Q. Please provide an example of such gaming.

A. If an Electric Supplier provides a customer with a 9-month contract for the months of September through May, the Company would be required to serve the customer at average rates during the remaining high cost months of June, July and August. The required standard offer for generation service should not be used to subsidize Electric Suppliers. Without revenue in the lower cost months, the revenue received by the Company will be insufficient to cover the cost of serving the customer during the high cost months. Therefore, it is necessary to require customers to take the standard offer for either the remainder of the Market Development Period, or 12 months, whichever is longer.

Q. If a customer is permitted to switch back and forth between an Electric Supplier and the Company's standard offer for generation service without limitation, what effect would this have?

A. If a customer is permitted to switch back and forth between an Electric Supplier and the Company's standard offer for generation service without limitation, the Company would be unable to plan for the load that it must serve. For example, assume that a 100 MW customer elects service from an alternative Electric Supplier during a period of low cost. If the Electric Supplier raises its rates during a period of high cost, then the customer has the option to return to the Company's standard offer for generation service. It is reasonable to allow the customer to return one time. However, if the customer is then free to switch back and forth repeatedly, then the Company would be unable to determine whether or not it must plan to serve that 100 MW customer for the next month, year or for the remainder of the Market Development Period. This inability to plan for the load it must serve will cause the Company to incur additional costs while providing benefits to Electric Suppliers.

Q. Does the proposed requirement limit the customer in choosing an alternative Electric Supplier?

A. No. It merely requires a customer, who chooses an Electric Supplier and then returns to the Company for the standard offer for generation service, to take the standard offer for either the remainder of the Market Development Period, or for 12 months, whichever is longer. A customer may move between alternative Electric Suppliers as frequently as specified in their specific contract with the supplier. A customer may initially select an alternative Electric Supplier at any time during the year.

Q. Do the rate schedules in the Standard Tariff reflect current rates as unbundled and adjusted according to the provisions of Part A and Am. Sub. S. B. No. 3?

A. Yes, with one exception. The Pole Attachment Schedules for both OPCO and CSP reflect the rates and provisions as filed by the Companies pursuant to Commission order in Case No. 96-1309-EL-CSS. The modifications reflected in this filing are the same as those currently pending before the Commission in Case Nos. 97-1568-EL-ATA for CSP and 97-1569-EL-ATA for OPCO.

Q. Please describe the Companies' proposed change to the availability of the existing Storage Water Heating and Load Management Water Heating provisions contained in the residential rate schedules.

A. The Companies propose to limit the availability of the Storage Water Heating and the Load Management Water Heating provisions to customers currently served under those provisions. As explained in the testimony of Company Witness Forrester, the regulated distribution Companies will no longer market the use of such water heating equipment. Consistent with that testimony, the availability of the water heating provisions under the residential rate schedules should then be limited to current customers.

Open Access Distribution Tariff

Q. Please describe the second, or Open Access Distribution Tariffs, filed by the Companies as part of Schedules UNB-1 and UNB-2.

A. The second tariff contains the Terms and Conditions of Open Access Distribution Service, Supplier Terms and Conditions of Service and open access distribution rate schedules and applicable riders. All of these documents are denoted by "D" in the page number and are contained as part of Schedules UNB-1 and UNB-2. If a customer chooses an alternative Electric Supplier, then the Companies provide only distribution-related services to that customer and the open access distribution rate schedules provide for such service. However, details are also required which relate to the provision of competitive services. These details are set forth for customers in the Terms and Conditions of Open Access Distribution Service. The details are also set forth for suppliers of competitive services in the Supplier Terms and Conditions of Service. Both terms and conditions address many of the items identified in Part A, §(E)(1).

Q. Please describe the provisions of the Terms and Conditions of Open Access Distribution Service.

A. The Terms and Conditions of Open Access Distribution Service are generally comparable to the existing Terms and Conditions of Service and relate to regulated distribution service provided by each Company. However, provisions and information for customers have been added. These relate to initially choosing an Electric Supplier, switching between Electric Suppliers, transmission service, losses, and metering and load profiling.

Q. What provisions are contained in the Supplier Terms and Conditions of Service?

A. The Supplier Terms and Conditions of Service contain provisions which relate to the suppliers of competitive services. While including a reference to a Commission certification process for Electric Suppliers, provisions for registration with the Companies are also included. Suppliers must also be aware of the Companies' processes regarding choice of Electric Supplier, obligations for obtaining transmission service, and other information required by the Companies.

Q. Please describe the provisions of the open access distribution rate schedules.

A. The open access distribution rate schedules contain provisions for the recovery of distribution charges and the applicable riders. The distribution rates contained in open access distribution rate schedules are identical to the distribution component of the rates set forth in the Standard Tariff. The provisions for minimum charge, delayed payment charge and due date, monthly billing demand, metered voltage adjustment and term of contract are also the same as contained in the Standard Tariff.

The open access distribution rate schedules also specify for the customer that transmission service is provided under the provisions of the applicable FERC Open Access Transmission Tariff. Either the customer or the customer's Electric Supplier may contract for transmission service, although it is anticipated that generally the Electric Supplier will make such arrangements. The open access distribution rate schedules, applicable only to those customers choosing an alternative Electric Supplier, also include provisions by which these customers may elect an alternative supplier of metering, meter data management and billing services.

Q. Does this mean that the Companies are making metering and billing services fully competitive?

A. No, it does not. Am. Sub. S. B. No. 3 §4928.04 directs the Commission to initiate a separate proceeding on or before March 31, 2003 in order to review whether or not there should be full competition for metering, billing and other services. However, as part of this filing, the Companies propose to provide an option for an alternative supplier of metering- and billing-related services to those customers who first choose an alternative Electric Supplier. The Electric Supplier would arrange such services for the customer. Company Witness Laine sponsors the operational issues related to implementation of this offering.

Q. Have the Companies proposed requirements for entities providing metering- and billing-related services?

A. Yes. The Companies' Supplier Terms and Conditions of Service detail the requirements for entities wanting to supply metering- and billing-related services to customers who have first selected an alternative Electric Supplier. Since there is no Commission certification process at this time, the Companies have included only a registration process for metering and billing providers in its filing. However, if the Commission were to develop a certification process for metering and billing providers, then the Companies would amend their Supplier Terms and Conditions of Service to include such a requirement.

Q. In general, what are the requirements for suppliers of metering- and billing-related services?

A. Generally, the suppliers of these services are held to the same standards as the Companies for providing metering and billing-related services. While providing an option for customers, the Companies' proposal will help to ensure that customers receive the same quality of service as they currently receive for such services. It is also important that entities who install or read meters detect and notify the appropriate Company of any hazardous conditions or conditions which present potential for injury.

Q. Do the open access distribution rate schedules include any time-of-day provisions?

A. No, they do not. While the cost of energy supply is related to a customer's time-of-day usage characteristics, distribution costs are not. The open access distribution rate schedules contain only provisions for the recovery of distribution costs, which are generally fixed in nature, and therefore do not contain time-differentiated provisions.

Q. Have the Companies identified any costs which are avoided for those customers that choose an alternative Electric Supplier?

A. Yes. The Companies will no longer incur any generation-related costs for customers who choose an alternative Electric Supplier. Customers may also see some transmission-related cost savings depending upon the characteristics of their aggregated group or the Electric Supplier's load. Accordingly, the Companies have included only distribution-related costs in the open access distribution rate schedules which apply to those customers choosing an alternative Electric Supplier.

Q. What riders apply to customers choosing an alternative Electric Supplier?

A. The riders for the Universal Service Fund, Energy Efficiency Fund, KWH Tax, Gross Receipts Tax Credit, Municipal Income Tax, Franchise Tax, Regulatory Asset Charge and Transition Charge apply to customers choosing an alternative Electric Supplier and therefore take service under the Companies' open access distribution rate schedules.

Q. Will these same riders apply to customers currently served under special contract?

A. Yes. The Commission has already determined that the rates and charges for contract customers must be adjusted for any changes in taxation, the universal service fund and energy efficiency fund (Part A, §(D)). Because Am. Sub. S. B. No. 3 §4928.40(E) requires that current customers continue to be customers of the regulated distribution company, regardless of delivery service voltage, the riders listed above will apply unless either Am. Sub. S. B. No. 3 or the customer's contract exempts the customer from any of the riders. The application of such riders is independent of the customer's alternative source of energy supply.

Overview of the Companies' Unbundling Approach

Q. Please describe the Companies' approach to the unbundling of revenues for use in development of the required schedules and rates.

A. For OPCO, the individual components of the cost of service study as filed in Case No. 94-996-EL-AIR were functionalized. The general methodology used the best available information from that case, and the allocation basis for each component, as the basis for functionalizing each item in the cost-of-service study. Once achieving a functional breakdown of the filed cost-of-service study, the results were adjusted to reflect the overall revenue level resulting from the settlement agreement as approved by the Commission. Finally, an adjustment was required in order to match the individual customer class revenues resulting from the settlement agreement. By taking the individual class settlement revenue and subtracting the distribution and transmission components, the gross generation component was derived, consistent with the provisions of Am. Sub. S. B. No. 3 §4928.34(A)(4). The resulting cost-of-service study is included in the Companies' filing as Schedule UNB-4 and is sponsored by Company Witness Roush.

Q. How was the unbundling of revenues for CSP achieved?

A. The cost-of-service from Case No. 91-418-EL-AIR was adjusted to reflect the following: the Commission's May 12, 1992 original order, the Commission's August 20, 1992 order on rehearing and final revenue resulting from the Commission's January 13, 1994 entry on remand. Similar to the methodology used for OPCO, adjustments were then required to match the individual class revenue requirements.

Q. Were any changes or adjustments made to either the OPCO or CSP cost-of-service studies regarding the allocation or refunctionalization of costs?

A. No. The Companies only made those adjustments necessary to comply with the Commission's orders in those two rate cases.

Q. What further adjustments were necessary in order to determine the "Unbundled Rates" as defined in Part A, §(B)(2)?

A. As required in Am. Sub. S. B. No. 3 §4928.34(A)(1) and Part A, §(C)(2), adjustments were required in order to utilize the AEP Companies' Open Access Transmission Tariff (OATT) as filed with FERC. The requirements, Am. Sub. S. B. No. 3 §4928.34(A)(2) and Part A, §(C)(3), also dictate that the adjusted distribution component be computed as the sum of the unbundled distribution and transmission components, less the revenue generated by the applicable OATT rate. Company Witness Bethel supports the OATT rate and Company Witness Roush supports the actual calculations.

Q. Were any further adjustments made to the generation component?

A. Yes, the generation component was adjusted to remove regulatory assets as specified in Part A, §(C)(1). Company Witness McCoy sponsors the amount for regulatory assets. Ancillary services, which are generation-related, were also reassigned to be part of the final unbundled transmission component consistent with the requirements of Part A, §(C)(2)(a).

Rate Design

Q. Please describe the general methodology used for the design of the distribution component of the Standard Tariffs.

A. Distribution-related costs are both demand- and customer-related. This classification is consistent with the Companies' cost-of-service studies as filed in Schedule UNB-4 and consistent with the treatment of such costs by the Staff in each Company's last rate case. Accordingly, distribution costs should be recovered through customer and demand charges where possible and the Companies' rate design methodology reflects this principle.

First, customer-related costs are partially recovered through a customer charge set equal to the existing tariff customer charge. Next, customers who currently receive service under demand metered schedules are charged for distribution services based on a demand (per KW/KVA) charge under the Standard Tariffs. However, where the demand charge for distribution exceeds the current total demand charge, the residual demand and customer costs are recovered through an energy charge. Customers without demand metering are charged for distribution services through an energy charge (per KWH).

Q. How were the distribution rates as contained in the Open Access Distribution Tariff developed?

A. The distribution rates contained in the Open Access Distribution Tariff are identical to those in the corresponding rate schedule of the Standard Tariff.

Q. Please describe the general methodology used for the transmission and generation components of the Standard Tariffs.

A. Because the transmission component of rates is required to be based on the applicable OATT, transmission should be recovered through a demand charge.

Therefore, demand charges were used for the recovery of transmission costs for customers with demand metering under existing rate schedules where possible. Transmission costs were recovered through an energy charge for customers without demand metering. Generation costs were recovered through a demand charge, energy charge, or both depending upon the structure of the existing rate schedule. In no event was the total recovery of distribution, transmission and generation costs through a demand charge allowed to exceed the demand charge of the current rate schedule.

Q. Please explain the basis for the charges contained in the Transition Charge Rider proposed by the Companies as part of their Open Access Distribution Tariffs.

A. The Transition Charge Rider reflects the recovery of transition charges as proposed by the Companies, consistent with the provisions of Part A, §(C)(1)(a)(i). As explained in the testimony of Company Witness Forrester, the transition charge is based on the positive difference between the generation component, excluding regulatory assets and the projected market price for generation.

Q. What market price was used in the development of the transition charge?

A. Company Witness Landon supports the anticipated monthly on-peak and off-peak market prices for 2001 which were then adjusted using the appropriate loss factors, load factors and time-of-use characteristics in order to create a weighted annual average market price for each customer class.

Q. Why was it necessary to adjust the market prices provided by Company Witness Landon?

A. The monthly market prices provided by Company Witness Landon reflect an overall monthly load factor comparable to the AEP System load factor. Because monthly load factors vary significantly by customer class, and load factor affects the realization (¢/KWH), an adjustment is required to create a market price on an equivalent basis to the generation component of the unbundled rates. Loss factor adjustments are also necessary for comparability with the generation component. Because energy consumption varies significantly by month for some customer classes, the monthly class on-peak and off-peak KWH were then used to determine a weighted annual average market price for each class.

Q. How were the actual transition charges then determined?

A. Transition revenues for each customer class were determined by taking the positive difference between the revenue resulting from the weighted annual average projected market price and the unbundled generation revenue, excluding regulatory assets. The transition revenue, divided by the appropriate billing determinants, resulted in the transition charges shown in the Transition Charge Rider as contained in Schedule UNB-1. Because the unbundled generation component of current rates is contained in either an energy charge, demand charge, or a combination of both, the design of the transition charge was consistent with the design and recovery of the generation component of unbundled rates.

Rate Adjustments

Q. Do the residential schedules reflect a 5% generation rate reduction as required by Am. Sub. S. B. No. 3 §4828.40(C) and Part A, §(C)(1)(c)?

A. Yes, the residential rate schedules reflect a 5% reduction "of the amount of that unbundled generation component." As specified in Am. Sub. S. B. No. 3 §4928.34(A)(4), as required for this calculation, the generation component is the residual amount after removing distribution, transmission and the other unbundled components (i.e., ancillary services, regulatory assets, demand side management and gross receipts tax). The property tax adjustment must also be removed according to this provision.

Q. Please describe what rate adjustments will be required if the FERC approves a change in the applicable OATT rates during the Market Development Period.

A. If the FERC were to approve a change in the applicable basic transmission rate during the Market Development Period, then a change in distribution rates would be required under the provisions of Am. Sub. S. B. No. 3 §4928.34(A)(2) and Part A, §(C)(3). The Companies would update the rates contained in their Standard Tariffs to reflect the changes in distribution and transmission rates. The Open Access Distribution Tariffs would also be updated to reflect the same changes in distribution rates.

Q. If FERC were to approve a change in the ancillary services rates, what adjustments would be required during the Market Development Period?

A. Because the revenues associated with ancillary services are generation-related, an adjustment would be required to the generation portion of the unbundled rates contained in the Standard Tariff. This adjustment would apply only during the Market Development Period.

Q. Please describe any rate changes that would be required if FERC were to approve a refund related to a change in transmission rates.

A. If FERC were to approve a refund related to a change in transmission rates, there would be no resulting refund for customers served under the Standard Tariffs. Because of the required interdependency of transmission and distribution rates, any reduction or refund in the transmission component would result in a corresponding increase in the distribution component of the unbundled rates.

Q. What is the effect of such a refund for customers taking service under the open access distribution rate schedules?

A. Customers taking service under the open access distribution rate schedules will see a required increase in the distribution charges that must be collected for the refund period. Customers who contract under the applicable Open Access Transmission Tariff will be subject to the refund provisions of that tariff. Customers whose Electric Supplier contracts for transmission service will be subject to the refund provisions of their contract with the Electric Supplier.

Q. Does this conclude your testimony?

A. Yes.

EXHIBIT NO.________

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Columbus Southern Power Company for Approval of Electric Transition Plan and Application for Receipt of Transition Revenues	Case No. 99-1729-EL-ETP
In the Matter of the Application of Ohio Power Company for Approval of Electric Transition Plan and Application for Receipt of Transition Revenues	Case No. 99-1730-EL-ETP

DIRECT TESTIMONY OF
MELINDA S. ACKERMAN
ON BEHALF OF
COLUMBUS SOUTHERN POWER COMPANY
AND
OHIO POWER COMPANY

INDEX TO DIRECT TESTIMONY OF
MELINDA S. ACKERMAN
PUCO CASE NOS. 99-___-EL-ETP and
99-___-EL-ETP

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BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO
DIRECT TESTIMONY OF
MELINDA S. ACKERMAN
ON BEHALF OF
COLUMBUS SOUTHERN POWER COMPANY
CASE NO. 99-___-EL-ETP
AND
OHIO POWER COMPANY
CASE NO. 99-___-EL-ETP

Personal Data

Q. Please state your name and business address.

A. My name is Melinda S. Ackerman. My business address is American Electric Power, 1 Riverside Plaza, Columbus, Ohio 43215.

Q. Please indicate by whom you are employed and in what capacity.

A. I am the Vice President of Human Resources for American Electric Power Service Corporation (AEPSC), a wholly owned subsidiary of American Electric Power Company, Inc. (AEP) the parent of Columbus Southern Power Company (CSP) and Ohio Power Company (OPCO).

Q. Please briefly describe your educational background and business experience.

A. I graduated from Morehead State University, Morehead, Kentucky, with a Bachelor of Business Administration (BBA) degree, with an emphasis in management. I also attended the University of Michigan's Human Resources Executive Program and am a member of the national HR organization SHRM (Society for Human Resource Management).

I have been employed in the American Electric Power System since 1965 in various positions at AEP's operating companies, and since 1991 with AEPSC.

While approximately half of my tenure has been in human resources, I have also worked in customer services, marketing, public affairs, generation and mining operations. In my present position I am responsible for directing the corporate human resources function which includes policy design and administration in the functional areas of compensation, benefits, personnel services (Equal Employment Opportunity/Affirmative Action, employee relations, employment), HR systems and processes, HR communications, and the field HR support staff.

Purpose of Testimony

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to sponsor the Employee Assistance Plan filed by CSP and OPCO in response to Part D of the PUCO's Rules for Electric Transition Plans.

Q. Was this Employee Assistance Plan prepared by you or under your supervision?

A. Yes.

General Description of the Employee Assistance Plan

Q. Please describe briefly the various components of CSP and OPCO's Employee Assistance Plan.

A. In the event of job displacement due to organizational restructuring, CSP and OPCO offer a diversified Employee Assistance Plan as outlined in Part D. The plan consists of programs to help the individual locate a new position, including an internal job searching program; a relocation assistance program; an educational assistance program; professional outplacement services and a re-employment workshop. It also includes programs designed to help the individual deal with the emotional and financial issues associated with the displacement, including employee/family counseling, a severance program providing up to 12 months of base pay, extended medical and life insurance benefits, and early retirement options for those who qualify. Each of these programs is described in greater detail in Part D. In this regard, as discussed in this testimony CSP and OPCO have not identified any positions affected by this legislation at this time. The responses that I am sponsoring in Part D are in the context of those Companies' existing employee assistance programs. Therefore, the CSP and OPCO's responses in Part D do not identify eligible employees.

Q. Do you believe that CSP and OPCO have provided for a reasonable Employee Assistance Plan?

A. Yes. It is a well-rounded program in that it addresses both employment and personal issues. It is also a very competitive package when compared to other companies.

Q. Are you seeking any cost recovery associated with the CSP and OPCO Employee Assistance Plan?

A. CSP and OPCO have not identified any positions affected by this legislation at this time, and therefore, CSP and OPCO are not requesting any cost recovery in the transition charge associated with the Employee Assistance Plan.

Q. Does this conclude your testimony?

A. Yes.

EXHIBIT NO.________

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Columbus Southern Power Company for Approval of Electric Transition Plan and Application for Receipt of Transition Revenues	Case No. 99-__-EL-ETP
In the Matter of the Application of Ohio Power Company for Approval of Electric Transition Plan and Application for Receipt of Transition Revenues	Case No. 99-__-EL-ETP

DIRECT TESTIMONY OF
J. CRAIG BAKER
ON BEHALF OF
COLUMBUS SOUTHERN POWER COMPANY
AND
OHIO POWER COMPANY

INDEX TO DIRECT TESTIMONY OF
J. CRAIG BAKER
PUCO CASE NOS. 99-___-EL-ETP and
99-___-EL-ETP

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BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO
DIRECT TESTIMONY OF
J. CRAIG BAKER
ON BEHALF OF
COLUMBUS SOUTHERN POWER COMPANY
CASE NO. 99-___-EL-ETP
AND
OHIO POWER COMPANY
CASE NO. 99-___-EL-ETP

Personal Data

Q. What is your name?

A. J. Craig Baker.

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

A. I am employed by American Electric Power Service Corporation (AEPSC) as Vice President-Transmission Policy.

Q. What is AEPSC?

A. AEPSC renders engineering, rate, financial, accounting, legal, planning and advisory services to the seven electric operating companies of the American Electric Power (AEP) System and to other AEP companies.

Q. What is the AEP System?

A. The AEP System is a physically integrated and centrally dispatched electric utility system for the generation, transmission and sale of electric energy. The System's operating companies furnish electric services in a seven-state area in the East Central Region of the United States. The operating companies in Ohio, Columbus Southern Power Company (CSP) and Ohio Power Company (OPCO), make retail sales to customers within their certified service areas and wholesale sales, that is, sales for resale, to other utility systems.

Q. What is your educational and employment background?

A. I possess a bachelor's degree in business administration from Walsh College and a masters degree in business administration from the University of Akron. I joined the AEP System in 1968 and through 1979 held various positions in the Computer Applications Division. I transferred to the System Operation Division in 1979 and held positions of Administrative Assistant and Assistant Manager. In 1985, I took the position of Staff Analyst in the Controllers Department and, in 1987, I became Manager-Power Marketing in the System Power Markets Department. In 1991, I became Director, Interconnection Agreements and Marketing. I became Vice President-Power Marketing for AEPSC and Senior Vice President of Energy Marketing for AEP Energy Services, Inc. in November 1996 and August 1997, respectively. On July 1, 1998 I became Vice President-Transmission Policy.

A major focus of my activities as Vice President-Transmission Policy has been AEP's participation in the formation of the Alliance Regional Transmission Organization (RTO) which I will describe in more detail in my testimony. In this regard, I have served as AEP's representative on the Alliance Steering Committee.

Purpose of Testimony

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to sponsor the AEP Companies' independent transmission plan, which is submitted as Appendix G to the Companies' transition plan filing, and to show how this plan reasonably complies with Section 4928.12 , Revised Code, which requires utilities which own transmission facilities in Ohio to transfer control of those entities to one or more qualifying transmission entities.

Q. Do OPCO and CSP own transmission facilities in Ohio?

A. Yes. OPCO and CSP are part of the AEP System. The AEP operating companies, Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company, own transmission facilities which are planned and operated as a single system. The AEP transmission system is among the most extensive and strongest transmission systems in the nation, stretching from southwestern Michigan to Central Virginia. A map of the System is attached as EXHIBIT NO. ___ JCB-1.

AEP's RTO Commitments

Q. Please describe AEP's commitment to transfer the control of its transmission facilities to a regional transmission organization (RTO).

A. AEP is committed to transferring the operation and control of its bulk transmission facilities to an RTO . AEP along with four other utility systems has filed with the Federal Energy Regulatory Commission (FERC), in Docket Nos. ER99-3144-000, et al., a proposal to form the Alliance RTO.

Q. Please explain the Alliance RTO proposal.

A. On June 3, 1999, AEP, along with FirstEnergy Corporation, Consumers Energy Company, the Detroit Edison Company and Virginia Electric and Power Company filed with the FERC under Section 203 of the Federal Power Act for transfer of control and/or ownership of jurisdictional transmission facilities to the Alliance RTO. A companion application under Section 205 of the FPA was filed for approval and contains the basic Alliance Agreement, Governance Structure, Protocols for Planning, Operation and Pricing, an Operation Agreement, an Agency Agreement and an Open Access Transmission Tariff (OATT). A summary of the documents filed with the FERC is included as Exhibit G-1 to Appendix G. In addition, the Alliance filing in its entirety is being submitted, in electronic form on compact discs, as part of Appendix G.

Q. Please describe the region encompassed by the Alliance RTO.

A. Overall, the Alliance RTO will serve a combined area of approximately 124,000 square miles in nine states encompassing a population of 26 million people and representing load of about 67,000 MW. As shown on EXHIBIT NO. ___ JCB-2, the Alliance RTO is larger than many of the RTOs approved thus far by the FERC including California, Pennsylvania-New Jersey-Maryland (PJM), the New York ISO and the New England ISO.

AEP supplies electricity through seven operating companies to three million customers in the states of Indiana, Kentucky, Michigan, Ohio, Tennessee, Virginia, and West Virginia. Its transmission system consists of approximately 22,000 miles of transmission lines. Consumers Energy supplies electricity to 1.6 million customers in Michigan through more than 5,300 miles of transmission lines. Detroit Edison's transmission system consists of approximately 3,000 miles of lines and serves 2.1 million customers in Michigan. FirstEnergy's transmission system consists of approximately 7,000 miles of lines and serves 2.2 million customers in Ohio and Pennsylvania. Virginia Power serves more than two million customers in Virginia and North Carolina through more than 6,000 miles of transmission lines.

Q. How much generating capacity is connected to the Alliance Companies' systems?

A. There is generating capacity of approximately 72,000 MW, or roughly ten percent of the electric supply in the United States, that is connected to the transmission facilities that the Alliance RTO will control. Such generating capacity includes approximately 24,000 MW connected to the AEP System, 8,000 MW connected to Consumers Energy's system, 10,000 MW connected to Detroit Edison's system, 12,000 MW connected to FirstEnergy's system.

Q. Please describe the governance structure of the Alliance RTO.

A. The Alliance, as proposed to FERC, will take one of two forms, depending upon whether certain "trigger" conditions are met. Specifically, if one or more of the participants owning at least $1 billion in transmission assets commits to divest its transmission facilities to an independent transmission company (Transco), and if a majority of the remaining owners consents, the Alliance RTO will be developed as the Alliance Transco, LLC, a limited liability company which, in turn, will be managed by a publicly-owned corporation. If the trigger conditions are not met, the entity will be developed as the Alliance Independent System Operator (ISO) – a not-for-profit corporation. In either case, it will be a totally separate entity, independent of the participating transmission-owners and any other electricity market participants.

As a practical matter, the Alliance participants expect that the Transco option will be triggered, since FirstEnergy which owns more than $1 billion in transmission assets, has stated that it intends to trigger the Alliance Transco as early as practical. Further, the Alliance participants favor the Transco form of organization, since its for-profit status will result in motivation for efficient operations, business-oriented solutions and innovative customer-driven approaches to transmission products and optimum grid utilization.

If the Alliance is developed as a Transco, participating owners need not sell their transmission facilities to the RTO. They have the option of entering into an agreement with the RTO under which it would operate their facilities much as would an ISO. This flexibility for transmission owners was an attractive feature for AEP, and we believe it will also be attractive to other transmission owners who have not yet committed to RTO participation, thereby enhancing the possibility that the Alliance will grow.

Q. When is the Alliance RTO expected to be in operation?

A. It is expected to begin operations during the year 2001.

Q. Has the FERC acted upon the Alliance participants' application?

A. Yes. On December 15, 1999, the FERC, in its public meeting, conditionally approved the Alliance RTO proposal. However, as of the date of completion of this testimony, the text of the FERC's order has not been made available to the public. AEP will supplement its filing as appropriate, when a copy of the order becomes available.

FERC RTO Standards

Q. What criteria are applied by the FERC in approving RTOs?

A. In Order No. 888, in which the FERC required all transmitting owning public utilities in the nation to offer open access transmission service, the agency specified 11 principles for independent system operators (ISOs). The 11 principles are:

1) The ISO's governance should be structured in a fair and non-discriminatory manner

2) An ISO and its employees should have no financial interest in the performance of any power market participant.

3) An ISO should provide open access to the transmission system and all services under its control at non-pancaked rates.

4) An ISO should have the primary responsibility in ensuring short-term reliability of grid operations.

5) An ISO should have control over the operation of interconnected transmission facilities within its region

6) An ISO should identify constraints on the system and be able to take operational actions to relieve those constraints.

7) An ISO should have appropriate incentives for efficient management and administration.

8) An ISO's transmission and ancillary service pricing policies should promote the efficient use of and investment in generation, transmission and consumption.

9) An ISO should make transmission information publicly available through an electronic information network.

10) An ISO should develop mechanisms to coordinate with neighboring control areas.

11) An ISO should establish an alternative dispute resolution process.

The FERC has applied and interpreted these standards in approving several ISOs

Q. Has the FERC issued any additional guidelines for regional transmission organization formation?

A. Yes. On May 13, 1999, the FERC issued a Notice of Proposed Rulemaking (NOPR) in which it proposes to encourage the formation of additional RTOs nationwide. The FERC used the broader term "RTO" in its NOPR to include a variety of different forms of organization in addition to ISO, i.e., Transcos and other forms of organizations. Two other notable features of the proposed rules are that (1) FERC does not propose to require utilities to participate in RTOs, but instead hopes to encourage RTO formation; and (2) The FERC declined to draw boundaries for proposed RTOs.

The NOPR proposes four basic characteristics and seven required functions of an RTO. The four basic characteristics are:

1) The RTO must be independent of market participants.
2) The RTO must be of sufficient scope and configuration to effectively perform its required functions and to support efficient and non-discriminatory power markets.
3) The RTO must have operational responsibility for all transmission facilities under its control.
4) The RTO must have exclusive authority for maintaining the short-term reliability of the grid it operates.

The seven required functions specify that an RTO must:

1) Administer its own transmission tariff and employ a pricing system that will promote efficient use and expansion of transmission and generation facilities;
2) Ensure the development and operation of market mechanisms to manage transmission congestion;
3) Develop and implement procedures to address parallel path flow issues;
4) Provide ancillary services in accordance with FERC requirements;

5) Be the single OASIS site for all transmission facilities under its control, and independently calculate Total Transmission Capability (TTC) and Available Transmission Capability (ATC);

6) Monitor the markets for transmission, ancillary services and bulk power to identify design flaws and market power and propose appropriate remedial actions; and

7) Plan the transmission system to ensure that it will be able to provide efficient, reliable, and non-discriminatory transmission service, and coordinate such efforts with the appropriate state authorities.

On December 15, 1999, the FERC, at its public meeting approved a final rule (Order No. 2000) in this rulemaking proceeding. As of the date of completion of this testimony, the text of Order No. 2000 has not been made available to the public.

Q. How do the FERC's principles for evaluation of RTOs compare with the specifications in Section 4928.12, Revised Code?

A. The FERC's principles are substantially the same as the specifications in the Ohio legislation. Therefore, an organization approved by FERC will qualify under the Ohio statute. Further, I am advised by counsel that to the extent that requirements or determinations under the Ohio statute conflict with FERC's requirements or determinations, the federal requirements or determinations would control.

Compliance With Section 4928.12(B) Revised Code

Q. Will the proposed Alliance RTO reasonably comply with Section 4928.12 (B), Revised Code?

A. Yes. In the following testimony, I will explain how the Alliance RTO proposal will comply with each of the requirements of the Ohio statute:

(1) THE TRANSMISSION ENTITY IS APPROVED BY THE FEDERAL ENERGY REGULATORY COMMISSION.

As indicated above, FERC on December 15, 1999 conditionally approved the Alliance proposal. However, as of the date of completion of this testimony, the text of the FERC's order has not been made available to the public. AEP will supplement its filing as appropriate, when a copy of the order becomes available.

(2) THE TRANSMISSION ENTITY EFFECTS SEPARATE CONTROL OF TRANSMISSION FACILITIES FROM CONTROL OF GENERATION FACILITIES.

The primary purpose of the Alliance, or any RTO, is to take control of transmission facilities out of the hands of integrated utilities which also own, control and sell electric generation, and place it in the hands of an independent entity. Such a transfer of control assures that the utilities cannot use control of the transmission system to favor their own generation sales.

The Alliance RTO, as proposed, would be an organization that is totally separate from the integrated utilities which are the initial participants, and any new participants. As indicated above, depending upon whether certain "trigger" conditions occur, the organization will take the form of either an independent system operator (ISO) or an independent transmission company (Transco). Under the ISO structure, an independent not-for-profit corporation would assume control of the Transmission System for the entity. The ISO structure is substantially similar to ISO proposals previously approved by FERC. If the Transco option is triggered, the entity would become a totally separate for-profit entity – the Alliance Transco LLC. The LLC would be managed, in turn, by a publicly-owned corporation.

Whatever form the organization takes, it will offer non-discriminatory open-access transmission service under an OATT which complies with FERC's requirements for such tariffs.

(3) THE TRANSMISSION ENTITY IMPLEMENTS, TO THE EXTENT REASONABLY POSSIBLE, POLICIES AND PROCEDURES DESIGNED TO MINIMIZE PANCAKED TRANSMISSION RATES WITHIN THIS STATE.

"Pancaked" transmission rates are a legacy of the manner in which rates for transmission service have historically been established by FERC, which has jurisdiction over such rates. Utilities have historically used their transmission systems to provide bundled electric service to their native load customers. The cost of their transmission systems, therefore, has been included in rates for bundled service to native load customers, principally retail and wholesale requirements customers. To the extent that utilities provided transmission service to third parties out of, into or across their systems, the revenues gained from such service were used as an offset to the transmission costs included in their rates for service to native load customers. Further, most unbundled transmission and inter-utility power sales were among neighboring entities or other utilities in the immediate region. Long-distance power transfers across many utility systems were not common.

The rates established by FERC for unbundled transmission service provided by a particular utility have been based upon the cost of that utility's transmission system, applied on a per-unit basis. Thus, each utility has its own rate, and a party transmitting power across several utilities must pay the applicable rate to each utility.

Greater competition in wholesale and retail electric markets brought on by FERC's open access transmission initiatives and state retail access programs has dramatically changed the way transmission systems are being utilized. Unbundled transmission transactions and long-distance bulk power sales are integral to the new, more competitive environment. Market participants have called for the minimization of the number of charges that must be paid for transactions involving multiple utility systems. Many have characterized the existing convention of charging separate charges for each system crossed as "pancaking" of rates – a term that made its way into the Ohio customer choice legislation.

RTOs can reduce rate pancaking as part of their function of combining multiple utility systems for purposes of transmission control and access. Ultimately the goal is to allow access across the combined systems at a single rate. However, the elimination of pancaking causes rate and revenue dislocations among the participants, by reducing the total amount of revenue received by the group of transmission owners and shifting the costs borne by the owners, and, ultimately their native load customers (since, as indicated above, transmission revenues are used to reduce native load cost of service). Of course, these effects become less of a problem as retail choice becomes a reality, and therefore may be seen as a transitional issue.

The Alliance RTO proposed to immediately reduce pancaking of rates in the Alliance region through a two-part rate in which a transmission user would pay one zonal fee when accessing a single rate zone, and no more than two rates – a zonal rate and a regional access charge (RAC), regardless of the number of Alliance participants' systems involved in a transaction. After a six-year transition period, a single grid-wide rate for the Alliance region will be established, thereby totally eliminating pancaking within the region.

According to the FERC's discussion, at its public meeting, of its order conditionally approving the Alliance proposal, the FERC has rejected the two-part rate proposal. However, as indicated, the text of that order is not yet available.

While establishment of RTOs minimizes pancaking, as long as there are multiple RTOs, there may be more than one charge for transaction involving more than one RTO. There are possible mechanisms for reducing such inter-RTO charges, such as rate "reciprocity" among RTOs, but just as is the case with intra-RTO consolidation of rates, such mechanisms involve considerations of revenue dislocations and cost shifts. Also, the existence of multiple charges for transactions over large areas gives some recognition to distance sensitivity – a factor which many believe is relevant in determining the reasonableness of transmission rates. As an extreme example, the issue of distance sensitivity asks why a transaction covering one or two states should be charged the same as a transaction from Florida to Canada. These inter-RTO issues thus involve complex questions which can only be resolved on a regional or national basis.

The Alliance RTO participants have proposed a framework for inter-RTO cooperation in order to address, among other things, possible reductions in charges for inter-RTO transactions.

(4) THE TRANSMISSION ENTITY IMPROVES SERVICE RELIABILITY WITHIN THIS STATE.

The Alliance RTO will improve service reliability by consolidating in one entity transmission reliability functions that formerly were performed by multiple utilities and control areas. This consolidation of functions will necessarily improve coordination and communication in matters relating to operation of the regional transmission system.

(5) THE TRANSMISSION ENTITY ACHIEVES THE OBJECTIVES OF AN OPEN AND COMPETITIVE MARKETPLACE, ELIMINATION OF BARRIERS TO MARKET ENTRY, AND PRECLUSION OF CONTROL OF BOTTLENECK ELECTRIC TRANSMISSION FACILITIES IN THE PROVISION OF RETAIL ELECTRIC SERVICE.

By achieving independent control of transmission facilities, the Alliance RTO will achieve the objectives of an open and competitive electric marketplace. The structural separation effected by the Alliance RTO, its obligation to offer non-discriminatory open access transmission service under the OATT, and additional safeguards contained in standards of conduct included in the Alliance governance documents will assure that there is no possibility that the participating utilities or any other participant in electric generation markets, can control "bottleneck" transmission facilities or in any other fashion raise barriers to market entry by virtue of their control of the transmission system.

(6) THE TRANSMISSION ENTITY IS OF SUFFICIENT SCOPE OR OTHERWISE OPERATES TO SUBSTANTIALLY INCREASE ECONOMICAL SUPPLY OPTIONS FOR CONSUMERS.

The substantial size of the Alliance RTO will help support a vigorously competitive market for electric generation. As currently configured, the Alliance RTO will encompass portions of nine contiguous states, serve a large population, and control a significant amount of transmission lines and facilities that are directly connected to a large amount of generation capacity. The Alliance RTO will also have significant transmission interconnections with neighboring systems. It will be interconnected with utilities located in the East Central Area Reliability

Council (ECAR), the Southeastern Electric Reliability Council (SERC), the Mid-America Interconnected Network (MAIN), Northeast Power Coordinating Council (NPCC), and Canada. The Alliance RTO will operate in a large transmission network that will facilitate power supply transactions across a broad region. With these attributes of size and central location, the Alliance RTO will foster a vigorous and competitive generation market.

According to the FERC's discussion, at its public meeting, of the order conditionally approving the Alliance RTO proposal, the order addresses the scope and regional configuration of the Alliance RTO proposal. However, as indicated, the text of that order is not yet available.

(7) THE GOVERNANCE STRUCTURE OR CONTROL OF THE TRANSMISSION ENTITY IS INDEPENDENT OF THE USERS OF THE TRANSMISSION FACILITIES, AND NO MEMBER OF THE BOARD OF DIRECTORS HAS AN AFFILIATION, WITH SUCH A USER OR WITH AN AFFILIATE OF A USER DURING THE MEMBER'S TENURE ON THE BOARD, SO AS TO UNDULY AFFECT THE TRANSMISSION ENTITY'S PERFORMANCE. FOR THE PURPOSE OF DIVISION (B) (7) OF THIS SECTION, A "USER" IS ANY ENTITY OR AFFILIATE OF THAT ENTITY THAT BUYS OR SELLS ELECTRIC ENERGY IN THE TRANSMISSION ENTITY'S REGION OR IN A NEIGHBORING REGION.

The Governance structure of the Alliance RTO will effect complete corporate separation of transmission control and tariff administration from participants in generation markets who use the system. If the entity takes the form of an ISO, it will be a not-for-profit corporation governed by a "non-stakeholder" board of directors. That is, no member of the board of directors may be affiliated with any transmission user, nor have any material business relationship with a transmission user. If, as expected, the RTO takes the form of a Transco, it will similarly be totally independent of transmission users by virtue of its status as a transmission-only company. The managing member of the Alliance Transco LLC will be a publicly-owned corporation. Market participants would be prohibited from owning more than a *de minimis* amount of stock in such a corporation The Alliance documents prohibit the Transco from acquiring, directly or indirectly, any ownership interest in generation assets that would make it a transmission user, and prohibit any director, officer or agent from having any involvement in the sale of electric energy at wholesale or retail except as required or allowed by the Alliance Agreement or the OATT.

According to the FERC's discussion, at its public meeting, of the order conditionally approving the Alliance RTO proposal, the order addresses certain aspects of the proposed governance structure. However, as indicated, the text of that order is not yet available.

(8) THE TRANSMISSION ENTITY OPERATES UNDER POLICIES THAT PROMOTE POSITIVE PERFORMANCE STANDARDS DESIGNED TO SATISFY THE ELECTRICITY REQUIREMENTS OF CUSTOMERS.

As indicated earlier, the Alliance participants believe that the structure of the Alliance Transco as a for-profit entity will supply the business incentives for positive performance. Such an entity will be customer-focused because its success will depend upon that focus. The combination of the organization's independence and profit motivation will foster development of innovative and flexible transmission products that will help make energy markets more robust and lead to optimum utilization of the transmission system.

(9) THE TRANSMISSION ENTITY IS CAPABLE OF MAINTAINING REAL-TIME RELIABILITY OF THE ELECTRIC TRANSMISSION SYSTEM, ENSURING COMPARABLE AND NONDISCRIMINATORY TRANSMISSION ACCESS AND NECESSARY SERVICES, MINIMIZING SYSTEM CONGESTION AND FURTHER ADDRESSING REAL OR POTENTIAL TRANSMISSION CONSTRAINTS.

The Alliance RTO will have exclusive authority for maintaining the short-term reliability of the transmission grid. The RTO will be responsible for maintaining the security and reliability of the integrated transmission system. It will serve as North American Electric Reliability Council (NERC) Security Coordinator for the Alliance region and will direct the control area operations of its participants. In this regard, it will engage in transmission system security monitoring, coordinate with other security coordinators, coordinate with and direct control areas within the RTO, implement reliability procedures, direct responses to emergency situations and provide congestion clearing solutions as necessary to maintain a secure transmission system.

The Alliance will assure comparable and non-discriminatory transmission access through its structural separation, as described above, and through the OATT.

The Alliance participants expect a robust short-term energy market to develop within the region that will provide reliable and economic solutions for congestion management and ancillary services. The Alliance Agreement and the Operating Protocol provide that the Alliance RTO will work with one or more regional power exchanges as may be proposed by market participants. The Alliance RTO will seek to develop a transmission congestion management structure that will allow an energy market to develop which properly prices energy in all locations with respect to grid interconnections. This approach will result in congestion being relieved primarily by the interaction of power markets.

The AEP Companies including OPCO and CSP are confident that the market will provide reliable and efficient congestion management solutions. In the interim, the Alliance RTO will manage congestion in accord with current and future NERC-recommended congestion management procedures to maintain firm transmission service. The Alliance RTO will not undertake redispatch procedures to accommodate requests for new firm transmission service when there is insufficient ATC to otherwise provide the service. The Alliance RTO will, however, facilitate generation redispatch arrangements between generation owners and those requesting firm service. The Alliance RTO will solicit bids for providing generation redispatch and firm transmission reassignment, and will post the bids on the OASIS.

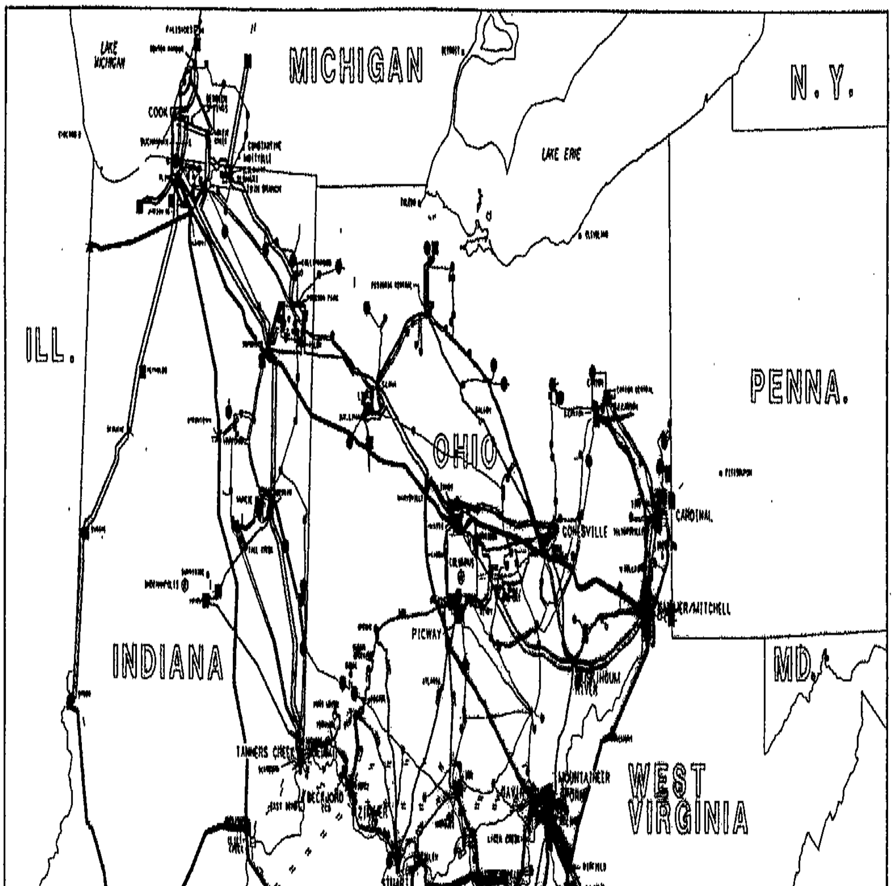
The Alliance RTO proposal includes a comprehensive planning process for the identification of and solution to real and potential transmission constraints.

Q. Are CSP and OPCO requesting the Commission to approve their independent transmission plan?

A. Yes, to the extent that the Commission has jurisdiction to approve such a plan, we are asking the Commission to approve our plan. Further, the plan may evolve as conditions change.

Q. Does this complete your direct testimony?

A. Yes, it does.



AMERICAN ELECTRIC POWER 1 RIVERSIDE PLAZA, COLUMBUS, OHIO

EXHIBIT NO. ___JCB-1
Page 1 of 1

ALLIANCE RTO OVERVIEW

Company	Generation Capacity (MW)	Approximate Control Area Peak Load (MW)	Sq. Miles Service Area	Miles of transmission	Population Served (millions)
AEP	23,900	20,600	45,400	22,000	7.0
Consumers Energy	8,000	7,500	27,800	5,300	4.0
Detroit Edison	10,300	10,700	7,600	3,000	5.0
FirstEnergy	12,000	12,000	13,200	7,000	5.5
Virginia Power	17,600	16,300	30,000	6,000	4.5
Total Alliance Participants	**71,800**	**67,100**	**124,000**	**43,300**	**26.0**

EXHIBIT NO.___JCB-2
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EXHIBIT NO.___

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Columbus Southern Power Company for Approval of Electric Transition Plan and Application for Receipt of Transition Revenues	Case No. 99-__-EL-ETP
In the Matter of the Application of Ohio Power Company for Approval of Electric Transition Plan and Application for Receipt of Transition Revenues	Case No. 99-__-EL-ETP

DIRECT TESTIMONY OF
JEFFREY B. BARTSCH
ON BEHALF OF
COLUMBUS SOUTHERN POWER COMPANY
AND
OHIO POWER COMPANY

INDEX TO DIRECT TESTIMONY OF
JEFFREY B. BARTSCH
PUCO CASE NOS. 99-___-EL-ETP and
99-___-EL-ETP

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BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO
DIRECT TESTIMONY OF
JEFFREY B. BARTSCH
ON BEHALF OF
COLUMBUS SOUTHERN POWER COMPANY
CASE NO. 99-___-EL-ETP
AND
OHIO POWER COMPANY
CASE NO. 99-___-EL-ETP

Personal Data

Q. Please state your name and business address.

A. My name is Jeffrey B. Bartsch. My business address is 1 Riverside Plaza, Columbus, Ohio 43215.

Q. Please indicate by whom you are employed and in what capacity.

A. I am the Manager of Tax Accounting Services for American Electric Power Service Corporation (AEPSC), a wholly owned subsidiary of American Electric Power Company, Inc. (AEP) the parent of Columbus Southern Power Company (CSP) and Ohio Power Company (OPCO). In my present position, I report to the Vice-President – Tax of AEPSC.

Q. Please briefly describe your educational background and business experience.

A. I earned a Bachelor of Business Administration Degree in Accounting from Ohio University in 1979. I am a Certified Public Accountant licensed in Ohio since 1981. I am also a member of the American Institute of Certified Public Accountants. I was first employed by Arthur Andersen & Co. in 1979 in the Audit section where I was assigned to various clients including those in the electric utility industry. In 1985, I accepted a position with the Tax Department at

AEPSC. Since that time I have held various positions until 1997 when I was promoted to my current position. As Manager of Tax Accounting Services, my responsibilities include oversight of the recordation of the tax accounting entries and records of AEP and its subsidiaries, including CSP and OPCO. I am also responsible for coordinating the development of Federal tax data to be provided by the AEPSC Tax Department in regulatory proceedings. Included in my responsibilities are the recordation of all accounting entries and records related to Statement of Financial Accounting Standards No. 109 (SFAS 109), "Accounting for Income Taxes" and the associated regulatory assets and liabilities.

Purpose of Testimony

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to describe SFAS 109 Regulatory Assets and the methodology utilized to calculate the SFAS 109 Regulatory Assets as of December 31, 1998, and projected at December 31, 1999, and December 31, 2000 related to Total Company SFAS 109 Regulatory Assets, Total Company Generation SFAS 109 Regulatory Assets and Ohio Retail Generation SFAS 109 Regulatory Assets, for CSP and OPCO, respectively. I also describe the calculations of the amount of SFAS 109 Regulatory Asset amortization contained in the last rate filings of CSP and OPCO. These amounts were provided to Company Witness McCoy for inclusion in Part F, §(B)(1)(a) – Regulatory Assets, of the Commission's Rules for Electric Transition Plans.

List of Exhibits

Q. What exhibits are you sponsoring in this proceeding?

A. I am sponsoring the following exhibits for CSP and OPCO:

Description

1. EXHIBIT NO. ___ JBB-1, SFAS 109 Regulatory Assets as of December 31, 1998
2. EXHIBIT NO. ___ JBB-2, Projected SFAS 109 Regulatory Assets as of December 31, 1999
3. EXHIBIT NO. ___ JBB-3, Projected SFAS 109 Regulatory Assets as of December 31, 2000
4. EXHIBIT NO. ___ JBB-4, SFAS 109 Amortization of Regulatory Assets in Last Rate Case Filings

Q. Were these exhibits prepared by you or under your supervision?

A. Yes.

Q. What data was used in the preparation of the exhibits that you are sponsoring?

A. Federal Income Tax schedules and work papers from CSP Case No. 91-418-EL-AIR and OPCO Case No. 94-996-EL-AIR; Company Financial Statements, FERC Form 1 Reports, and tax accounting and depreciation system printouts as of December 31, 1998; and functional generation and Ohio retail jurisdictional factors as provided by Company Witness Roush.

Discussion of SFAS 109 Regulatory Assets

Q. Briefly describe what SFAS 109 Regulatory Assets are and how they arose.

A. Regulatory assets exist as a result of past regulatory practices and would not exist in the absence of regulation and their probable recovery through rates in the future.

SFAS 109 Regulatory Assets are regulatory assets related to deferred income taxes that were not recorded in the past due to regulatory practices in which the current tax benefits of temporary book/tax differences were passed-through to rate payers immediately. This type of "flow-through" accounting was permitted under Statement of Financial Accounting Standards No. 71, Accounting for the Effects of Certain Types of Regulation (SFAS 71). SFAS 71 did not require the recordation of deferred income tax liabilities, unless required under the Internal Revenue Code, as long as recovery of these flowed-through current income tax benefits was probable through the ratemaking process in a future period when the temporary differences reverse causing an increase in the then current tax expense.

SFAS 109 required, starting in 1993, that "an enterprise shall recognize a deferred tax liability or asset for all temporary differences" and that "regulated enterprises that meet the criteria for application of FASB Statement No. 71, Accounting for the Effects of Certain Types of Regulation, are not exempt from the requirements of this statement. Specifically, this statement . . . requires recognition of a deferred tax liability for tax benefits that are flowed through to customers when temporary differences originate. . ." and "If, as a result of an action by a regulator, it is probable that the future increase or decrease in taxes payable for 'Deferred Tax Liabilities' will be recovered from or returned to customers through future rates, an asset or liability is recognized for that probable future revenue or reduction in future revenue pursuant to paragraphs 9-11 of Statement 71. That asset or liability is a temporary difference for which a deferred tax liability or asset shall be recognized."

In this instance, the ratepayer's obligation to repay the utility (and thus the regulatory asset) existed prior to the issuance of SFAS 109, but SFAS 71 effectively allowed it to be netted against the deferred income tax liability. The issuance of SFAS 109 had no impact on the ratepayers' obligation to pay utilities such amounts in the future, nor on the utilities' obligations to pay the deferred income tax liabilities to the government in the future. The issuance of SFAS 109 merely required that the existing regulatory asset that resulted from flow-through rate treatment and the existing deferred income tax liability be separately recognized in the financial statements.

Q. Has the Public Utilities Commission of Ohio historically allowed the recovery of SFAS 109 Regulatory Assets in setting rates?

A. Yes. Even before the issuance of SFAS 109, previously flowed-through tax benefits were reflected in utility revenue requirements in setting utility rates as the related tax benefit reversed and the deferred income tax liability was repaid to the IRS. This regulatory treatment has continued, and SFAS 109 has had no impact on the regulatory treatment of income taxes. Based on this rate treatment, which provides for recovery of flowed-through tax benefits when the temporary differences reverse, recovery of these amounts is probable and the amounts qualify for recordation as regulatory assets.

Determination of SFAS 109 Jurisdictional Generation Related Regulatory Assets as of December 31, 1998

Q. Briefly explain how the SFAS 109 Regulatory Assets as of December 31, 1998, were determined.

A. The individual SFAS 109 Regulatory Assets for CSP and OPCO are maintained in a detailed tax accounting system, which was developed as a result of SFAS 109 being implemented. At the inception of SFAS 109, a regulatory asset was established on the balance sheet for all book/tax temporary differences that existed, but for which no deferred income taxes were recorded on the books as a result of past Commission orders and accounting practices. These balances have been updated monthly since that initial date based on Schedule M and rate-based deferred tax activity.

Q. Are these balances maintained on a functional and a jurisdictional basis?

A. No.

Q. How were the individual SFAS 109 Regulatory Asset items as of December 31, 1998, functionalized and jurisdictionalized to determine the Ohio retail generation portion?

A. As shown on EXHIBIT NO. ___ JBB-1, for non-property related items, the Ohio retail generation portion of the regulatory assets was determined by multiplying the total Company regulatory asset item, from the tax accounting system as of

December 31, 1998, by the appropriate generation and jurisdictional allocation factors as provided by Company Witness Roush.

Q. How was the property related SFAS 109 Regulatory Asset for generation plant allocated on a jurisdictional generation related basis?

A. Due to the complexity of the property accounts and the various temporary differences and deferred taxes involved, this allocation had to be made on a more detailed level. This computation was performed by utilizing the principles contained in SFAS 109, in which the net book basis of generation plant (obtained from the Company financial statements and FERC Form 1 Reports) is compared to the net tax basis of generation plant (obtained from the Company tax depreciation system). The difference between the book and tax basis represents the taxable temporary difference, which will reverse in future years. This temporary difference was multiplied by the current income tax rates to determine the amount of deferred Federal income taxes (DFIT) required under SFAS 109. The difference between the deferred income taxes required and the appropriate deferred income taxes recorded on the books for rates represents the amount of additional deferred income taxes that will be owed to the taxing authorities in the future and must be collected through rates. This amount is then grossed-up, since any amounts collected in rates will result in a future taxable event. The grossed-up amount represents the Regulatory Asset recorded on the books for generation plant.

Q. How were deferred Federal income taxes for generation plant allocated to the Ohio retail jurisdiction?

A. The deferred Federal income taxes were derived from the Company tax depreciation system. For items for which jurisdictional information exists, the historic per books Ohio deferred income tax amounts were used. For items for which full-deferred tax normalization exists in all jurisdictions, a jurisdictional allocation was made based on factors received from Company Witness Roush. For non-depreciation, plant book/tax basis differences, the deferred income taxes were then further allocated based on production plant ratios since these balances are not maintained on a functional plant basis.

Q. How was the SFAS 109 Regulatory Asset related to state income taxes calculated?

A. These calculations were performed essentially the same as explained above. The total temporary book/tax difference was multiplied by the effective state income tax rates for CSP and OPCO as determined from the state income tax returns filed in Kentucky by CSP and in West Virginia and Illinois by OPCO. Since no deferred state income taxes have ever been authorized by the Commission in past rate orders, there was no deferred state income tax offset to the amounts calculated.

Determination of Projected SFAS 109 Jurisdictional Generation Related Regulatory Assets as of December 31, 1999, and December 31, 2000

Q. Briefly describe how the projected SFAS 109 Regulatory Asset balances as of December 31, 1999, and December 31, 2000, were determined.

A. As shown on EXHIBIT NO. ___ JBB-2 and EXHIBIT NO. ___ JBB-3, the SFAS 109 Regulatory Asset balances as of December 31, 1998, were rolled forward based on information available for actual account activity recorded through September 30, 1999 in the tax accounting system. This activity level was then extrapolated to estimate what the balances would be as of December 31, 1999, and December 31, 2000.

Q. Why was this methodology used?

A. This methodology was utilized because it is very difficult to forecast the regulatory asset balances and it is my judgement that the trend of account activity recorded through September 30, 1999, should continue for the remainder of 1999 and into the year 2000.

Q. Was this methodology used for all SFAS 109 Regulatory Asset items?

A. No. For items that are very difficult to forecast and for which trending information is not available, the SFAS 109 Regulatory Asset balances were not changed from those balances as of September 30, 1999.

Determination of SFAS 109 Jurisdictional Generation Related Regulatory Asset Amortization in Last Rate Filings.

Q. Has this Commission allowed the deferral and amortization of SFAS 109 Regulatory Assets for CSP and OPCO, respectively, in previous rate proceedings?

A. Yes. Review of previous Commission orders and rate case information has indicated that the Commission has embraced flow-through tax accounting for some items. These accounting practices resulted in the establishment of SFAS 109 Regulatory Assets as discussed earlier in my testimony. In the most recent rate filings for CSP (12 months ended 12/31/91 test year – Case No. 91-418-EL-

AIR) and OPCO (12 months ended 03/31/95 test year – Case No. 94-996-EL-AIR), the net flow-through tax accounting resulted in the amortization of SFAS 109 Regulatory Assets.

Q. Briefly describe how the SFAS 109 Jurisdictional Regulatory Asset amortization was determined from these most recent rate filings.

A. As shown on EXHIBIT NO. ___ JBB-4, the amount of SFAS 109 Regulatory Asset amortization was determined by reviewing the jurisdictional Schedule M and related deferred Federal income tax information contained in the Federal income tax schedules and workpapers based on the CSP Commission Order (Case No. 91-418-EL-AIR) and on the "3 & 9" updated OPCO rate filings in Case No. 94-996-EL-AIR, respectively.

The total Schedule M adjustment (excluding permanent items) was multiplied by the then-current Federal income tax rate. This current tax expense/credit was then added to the appropriate deferred Federal income tax expense to arrive at the net additional Federal income tax expense included in rates. This amount represents the higher Federal income tax expense being recovered currently in rates due to earlier application of flow-through tax accounting practices.

This amount is then grossed-up to a revenue requirement level in order to determine the amount of regulatory assets being amortized in rates.

Q. Explain how the generation portion of the Ohio retail SFAS 109 Regulatory Asset amortization was determined.

A. As shown on EXHIBIT NO. ___ JBB-4, the jurisdictional generation related regulatory asset amortization amount was determined using the same methodology as explained above, except that all of the Schedule M items and deferred Federal income tax amounts were functionalized on a generation basis. The allocation factors used to functionalize the Schedule M's and deferred taxes were obtained from Company Witness Roush.

Q. Does this conclude your direct testimony?

A. Yes.

CSP / OPCO
SFAS 109 REGULATORY ASSETS
As of December 31, 1998

Columbus Southern Power Co.			Total Company	Generation Total Company	Generation Ohio
Regulatory Asset <Liability> - FASB 109 - Federal					
	Generation	Ohio Retail			
Net Regulatory Assets:					
Property Related	WP Exhibit No. __JBB-2		262,493,400	210,669,788	204,544,774
Tax Depreciation - DuMont Test Center	0.0000%	0.0000%	5,019	0	0
Capd Post-in-Service Carrying Charge - Zimmer Plant	100.0000%	100.0000%	23,155,380	23,155,380	23,155,380
Capd Carrying Charge - Defd Expense - Zimmer Plant	100.0000%	100.0000%	14,121	14,121	14,121
Clearing Accounts	58.6249%	96.4900%	43,806	25,681	24,780
Provision - Self Insurance	58.6249%	96.4900%	(937,756)	(549,759)	(530,462)
Provision - Workers Compensation	41.3780%	97.6500%	(952,275)	(394,032)	(384,772)
Gain on Reacquired Debt - F/T	58.6249%	96.4900%	(29,234)	(17,138)	(16,536)
Gross Receipts Tax	69.1780%	100.0000%	459,974	318,201	318,201
All Other Regulatory Assets	58.6249%	96.4900%	(2,097)	(1,229)	(1,186)
Net Regulatory Liabilities			2,449,155	1,851,240	1,848,436
Net Regulatory Asset <Liability>			286,699,493	235,072,253	228,972,736
Regulatory Asset <Liability> - FASB 109 - State					
Net Regulatory Asset			49,000	26,000	25,000

Ohio Power Co.			Total Company	Generation Total Company	Generation Ohio
Regulatory Asset <Liability> - FASB 109 - Federal					
	Generation	Ohio Retail			
Net Regulatory Assets:					
Property Related	WP Exhibit No. __JBB-2		386,932,421	159,039,026	149,832,960
Various DuMont Test Center	*0.0000%*	*91.8300%*	1,078,711	0	0
AOFUDC - TIDD PFBC	100.0000%	91.8300%	1,374,092	1,374,092	1,261,829
Property Taxes	57.1179%	100.0000%	(5,280,825)	(3,016,296)	(3,016,296)
Clearing Accounts	57.1179%	100.0000%	551,711	315,126	315,126
Provision - Self Insurance	57.1179%	100.0000%	(1,339,021)	(764,821)	(764,821)
Provision - Workers Compensation	50.8499%	100.0000%	(1,843,731)	(937,535)	(937,535)
Book Provision - Uncollectible Accounts	0.0000%	100.0000%	(890,465)	0	0
Tax Deferral - Franchise Costs	0.0000%	100.0000%	(214,068)	0	0
All Other Regulatory Assets	57.1179%	91.8300%	9,829	5,614	5,155
Net Regulatory Liabilities			(12,014,436)	(304,982)	(278,602)
Net Regulatory Asset <Liability>			368,364,218	155,710,224	146,417,816
Regulatory Asset <Liability> - FASB 109 - State					
Net Regulatory Asset			21,442,000	7,881,000	7,238,000

CSP / OPCO
PROJECTED SFAS 109 REGULATORY ASSETS
As of December 31, 1999

Columbus Southern Power Co.

Regulatory Asset <Liability> - FASB 109 - Federal

	Generation	Ohio Retail	Total Company	Generation Total Company	Generation Ohio
Net Regulatory Assets:					
Property Related	Allocated	Allocated	249,714,000	200,414,000	194,587,000
Tax Depreciation - DuMont Test Center	0.0000%	0.0000%	5,000	0	0
Capd Post-in-Service Carrying Charge - Zimmer Plant	100.0000%	100.0000%	23,155,000	23,155,000	23,155,000
Capd Carrying Charge - Defd Expense - Zimmer Plant	100.0000%	100.0000%	9,000	9,000	9,000
Clearing Accounts	58.6249%	96.4900%	(942,000)	(552,000)	(533,000)
Provision - Self Insurance	58.6249%	96.4900%	(542,000)	(318,000)	(307,000)
Provision - Workers Compensation	41.3780%	97.6500%	(469,000)	(194,000)	(189,000)
Gain on Reacquired Debt - F/T	58.6249%	96.4900%	3,000	2,000	2,000
Gross Receipts Tax	69.1780%	100.0000%	(73,000)	(51,000)	(51,000)
All Other Regulatory Assets	58.6249%	96.4900%	(2,000)	(1,000)	(1,000)
Net Regulatory Liabilities			2,350,000	1,788,000	1,786,000
Net Regulatory Asset <Liability>			273,208,000	224,252,000	218,458,000

Regulatory Asset <Liability> - FASB 109 - State

	Total Company	Generation Total Company	Generation Ohio
Net Regulatory Asset	49,000	26,000	25,000

Ohio Power Co.

Regulatory Asset <Liability> - FASB 109 - Federal

	Generation	Ohio Retail	Total Company	Generation Total Company	Generation Ohio
Net Regulatory Assets:					
Property Related	Allocated	Allocated	367,889,000	151,212,000	142,459,000
Various DuMont Test Center	0.0000%	91.8300%	1,079,000	0	0
AOFUDC - TIDD PFBC	100.0000%	91.8300%	1,374,000	1,374,000	1,262,000
Property Taxes	57.1179%	100.0000%	(5,234,000)	(2,989,000)	(2,989,000)
Clearing Accounts	57.1179%	100.0000%	(592,000)	(338,000)	(338,000)
Provision - Self Insurance	57.1179%	100.0000%	(2,313,000)	(1,321,000)	(1,321,000)
Provision - Workers Compensation	50.8499%	100.0000%	(3,017,000)	(1,534,000)	(1,534,000)
Book Provision - Uncollectible Accounts	0.0000%	100.0000%	(1,316,000)	0	0
Tax Deferral - Franchise Costs	0.0000%	100.0000%	(196,000)	0	0
All Other Regulatory Assets	57.1179%	91.8300%	10,000	6,000	5,000
Net Regulatory Liabilities			(10,642,000)	(149,000)	(134,000)
Net Regulatory Asset <Liability>			347,042,000	146,261,000	137,410,000

Regulatory Asset <Liability> - FASB 109 - State

	Total Company	Generation Total Company	Generation Ohio
Net Regulatory Asset	21,442,000	7,881,000	7,238,000

EXHIBIT NO.___JBB-3

CSP / OPCO
PROJECTED SFAS 109 REGULATORY ASSETS
As of December 31, 2000

Columbus Southern Power Co.	Generation	Ohio Retail	Total Company	Generation Total Company	Generation Ohio
Regulatory Asset <Liability> - FASB 109 - Federal					
Net Regulatory Assets:					
Property Related	Allocated	Allocated	236,935,000	190,158,000	184,629,000
Tax Depreciation - DuMont Test Center	0.0000%	0.0000%	5,000	0	0
Capd Post-in-Service Carrying Charge - Zimmer Plant	100.0000%	100.0000%	23,155,000	23,155,000	23,155,000
Capd Carrying Charge - Defd Expense - Zimmer Plant	100.0000%	100.0000%	5,000	5,000	5,000
Clearing Accounts	58.6249%	96.4900%	(942,000)	(552,000)	(533,000)
Provision - Self Insurance	58.6249%	96.4900%	(542,000)	(318,000)	(307,000)
Provision - Workers Compensation	41.3780%	97.6500%	(469,000)	(194,000)	(189,000)
Gain on Reacquired Debt - F/T	58.6249%	96.4900%	3,000	2,000	2,000
Gross Receipts Tax	69.1780%	100.0000%	(73,000)	(51,000)	(51,000)
All Other Regulatory Assets	58.6249%	96.4900%	(2,000)	(1,000)	(1,000)
Net Regulatory Liabilities			2,251,000	1,726,000	1,724,000
Net Regulatory Asset <Liability>			260,326,000	213,930,000	208,434,000
Regulatory Asset <Liability> - FASB 109 - State					
Net Regulatory Asset			49,000	26,000	25,000

Ohio Power Co	Generation	Ohio Retail	Total Company	Generation Total Company	Generation Ohio
Regulatory Asset <Liability> - FASB 109 - Federal					
Net Regulatory Assets:					
Property Related	Allocated	Allocated	348,845,000	143,384,000	135,084,000
Various DuMont Test Center	0.0000%	91.8300%	1,079,000	0	0
AOFUDC - TIDD PFBC	100.0000%	91.8300%	1,374,000	1,374,000	1,262,000
Property Taxes	57.1179%	100.0000%	(5,234,000)	(2,989,000)	(2,989,000)
Clearing Accounts	57.1179%	100.0000%	(592,000)	(338,000)	(338,000)
Provision - Self Insurance	57.1179%	100.0000%	(2,313,000)	(1,321,000)	(1,321,000)
Provision - Workers Compensation	50.8499%	100.0000%	(3,017,000)	(1,534,000)	(1,534,000)
Book Provision - Uncollectible Accounts	0.0000%	100.0000%	(1,316,000)	0	0
Tax Deferral - Franchise Costs	0.0000%	100.0000%	(196,000)	0	0
All Other Regulatory Assets	57.1179%	91.8300%	10,000	6,000	5,000
Net Regulatory Liabilities			(9,279,000)	3,000	5,000
Net Regulatory Asset <Liability>			329,361,000	138,585,000	130,174,000
Regulatory Asset <Liability> - FASB 109 - State					
Net Regulatory Asset			21,442,000	7,881,000	7,238,000

CSP / OPCO
SFAS 109 AMORTIZATION OF REGULATORY ASSETS IN LAST RATE CASE FILINGS

Columbus Southern Power Co.
Test Period: 12 Months Ended 12-31-91

Case No. 91-418-EL-AIR

	Total Ohio Retail	Generation Ohio Retail
Total Schedule M Adjustments — Add <Deduct>	(26,629,000)	(16,367,000)
Less: Permanent Schedule M's	56,000	23,000
Temporary Schedule M Adjustments	(26,685,000)	(16,390,000)
Current Federal Income Tax Rate @ Filing Date	34%	34%
Current Federal Income Tax Expense <Credit>	(9,073,000)	(5,573,000)
Deferred Federal Income Tax Expense <Credit>	13,755,000	8,454,000
Net Federal Income Tax Expense <Credit> in Ratemaking	4,682,000	2,881,000
Gross-Up to Revenue Requirement Level	2,412,000	1,484,000
Increase in Revenues due to Federal Income Taxes	7,094,000	4,365,000
Net Regulatory Asset Amortization	(7,094,000)	(4,365,000)

Ohio Power Co.
Test Period: 12 Months Ended 3-31-95

Case No. 94-996-EL-AIR

	Total Ohio Retail	Generation Ohio Retail
Total Schedule M Adjustments — Add <Deduct>	(13,245,000)	(364,000)
Less: Permanent Schedule M's	(12,557,000)	(6,431,000)
Temporary Schedule M Adjustments	(688,000)	6,067,000
Current Federal Income Tax Rate @ Filing Date	35%	35%
Current Federal Income Tax Expense <Credit>	(241,000)	2,123,000
Deferred Federal Income Tax Expense <Credit>	5,008,000	1,482,000
Net Federal Income Tax Expense <Credit> in Ratemaking	4,767,000	3,605,000
Gross-Up to Revenue Requirement Level	2,567,000	1,941,000
Increase in Revenues due to Federal Income Taxes	7,334,000	5,546,000
Net Regulatory Asset Amortization	(7,334,000)	(5,546,000)

Columbus Southern Power Co.
SFAS 109 REGULATORY ASSETS
Generation Plant Related Computations
As of December 31, 1998

Columbus Southern Power Co.			Generation Total Company	Generation Ohio
Federal Income Tax Computations:				
Book Cost of Generation Plant			1,521,610,996	
Less: Land			(6,593,649)	
Depreciable Book Cost			1,515,017,347	
Less: Accumulated Book Depreciation			(549,496,764)	
Net Book Value - Generation Plant	A		965,520,583	
Tax Cost of Generation Plant (Excludes Land)			1,166,721,789	
Less: Accumulated Tax Depreciation			(852,110,480)	
Net Tax Basis - Generation Plant	B		314,611,309	
Temporary Book vs. Tax Difference	A - B	96.4900%	650,909,274	628,062,358
Federal Income Tax Rate			35%	35%
Required Deferred F.I.T. per SFAS 109	C		(227,818,246)	(219,821,825)
Depreciation Related Deferred F.I.T.			(85,874,778)	(82,304,984)
Book/Tax Basis Overhead Related Deferred F.I.T.			(5,008,106)	(4,562,738)
Ratemaking Deferred F.I.T. per SFAS 109	D		(90,882,884)	(86,867,722)
Additional Deferred F.I.T. Required per SFAS 109	C - D		(136,935,362)	(132,954,103)
SFAS 109 Regulatory Asset			136,935,362	132,954,103
Gross-Up Adjustment			73,734,426	71,590,671
Gross Regulatory Asset - SFAS 109 - Federal			210,669,788	204,544,774

State Income Tax Computations:				
Temporary Book vs. Tax Difference	A - B	96.4900%	650,909,274	628,062,358
Effective State Income Tax Rate			0.0040%	0.0040%
Required Deferred S.I.T. per SFAS 109			(26,000)	(25,000)
Ratemaking Deferred S.I.T. per SFAS 109			0	0
Deferred S.I.T. Required per SFAS 109			(26,000)	(25,000)
SFAS 109 Regulatory Asset			26,000	25,000
Gross-Up Adjustment			0	0
Gross Regulatory Asset - SFAS 109 - State			26,000	25,000

Ohio Power Company
SFAS 109 REGULATORY ASSETS
Generation Plant Related Computations
As of December 31, 1998

Ohio Power Co.			Generation Total Company	Generation Ohio
Federal Income Tax Computations:				
Book Cost of Generation Plant			2,622,942,777	
Less: Land			(5,381,350)	
Depreciable Book Cost			2,617,561,427	
Less: Accumulated Book Depreciation			(1,458,080,889)	
Net Book Value - Generation Plant	A		1,159,480,538	
Tax Cost of Generation Plant (Excludes Land)			2,085,844,869	
Less: Accumulated Tax Depreciation			(1,665,400,768)	
Net Tax Basis - Generation Plant	B		420,444,101	
Temporary Book vs. Tax Difference	A - B	91.8300%	739,036,437	678,657,160
Federal Income Tax Rate			35%	35%
Required Deferred F.I.T. per SFAS 109	C		(258,662,753)	(237,530,006)
Depreciation Related Deferred F.I.T.			(110,058,477)	(99,629,968)
Book/Tax Basis Overhead Related Deferred F.I.T.			(45,228,909)	(40,508,614)
Ratemaking Deferred F.I.T. per SFAS 109	D		(155,287,386)	(140,138,582)
Additional Deferred F.I.T. Required per SFAS 109	C - D		(103,375,367)	(97,391,424)
SFAS 109 Regulatory Asset			103,375,367	97,391,424
Gross-Up Adjustment			55,663,659	52,441,536
Gross Regulatory Asset - SFAS 109 - Federal			159,039,026	149,832,960
State Income Tax Computations:				
Temporary Book vs. Tax Difference	A - B	96.4900%	739,036,437	678,657,160
Effective State Income Tax Rate			1.0552%	1.0552%
Required Deferred S.I.T. per SFAS 109			(7,798,000)	(7,162,000)
Ratemaking Deferred S.I.T. per SFAS 109			0	0
Deferred S.I.T. Required per SFAS 109			(7,798,000)	(7,162,000)
SFAS 109 Regulatory Asset			7,798,000	7,162,000
Gross-Up Adjustment			83,000	76,000
Gross Regulatory Asset - SFAS 109 - State			7,881,000	7,238,000

EXHIBIT NO.___

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Columbus Southern Power Company for Approval of Electric Transition Plan and Application for Receipt of Transition Revenues	Case No. 99-__-EL-ETP
In the Matter of the Application of Ohio Power Company for Approval of Electric Transition Plan and Application for Receipt of Transition Revenues	Case No. 99-__-EL-ETP

DIRECT TESTIMONY OF
DENNIS W. BETHEL
ON BEHALF OF
COLUMBUS SOUTHERN POWER COMPANY
AND
OHIO POWER COMPANY

INDEX TO DIRECT TESTIMONY OF
DENNIS W. BETHEL
PUCO CASE NOS. 99-___-EL-ETP and
99-___-EL-ETP

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4.	Transmission Revenues	4
5.	Ancillary Service Revenues	8

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO
DIRECT TESTIMONY OF
DENNIS W. BETHEL
ON BEHALF OF
COLUMBUS SOUTHERN POWER COMPANY
CASE NO. 99-___-EL-ETP
AND
OHIO POWER COMPANY
CASE NO. 99-___-EL-ETP

Personal Data

Q. Please state your name and business address.

A. My name is Dennis W. Bethel. My business address is 1 Riverside Plaza, Columbus, Ohio 43215.

Q. Please indicate by whom you are employed and in what capacity.

A. I am employed by American Electric Power Service Corporation (AEPSC). My position is Manager-Transmission Contracts and Regulatory Support.

Q. Please briefly describe your educational background and business experience.

A. In 1973, I earned a Bachelor of Science Degree in Electrical Engineering from the University of Evansville. I have also completed several post-graduate courses at Ball State University and the American Electric Power System Management Development Program at Ohio State University. I have 26 years of experience in the electric utility industry, all with the American Electric Power (AEP) System. In 1973 I joined the AEP System as a Commercial and Industrial Engineer in the Customer Service Department of Indiana Michigan Power Company (I&M). In 1977 I transferred to I&M's Rate Department as a Rate Analyst. In that position, I was responsible for the preparation of load research reports, development of class and jurisdictional cost-of-service studies, monthly fuel and purchased power adjustments, wholesale power contract administration and rate design. In 1980 I transferred to the AEPSC Rate Research and Design Division. My responsibilities in AEPSC's Rate Department included supervision of projects relating to rate design, rate research, jurisdictional and class cost-of-service studies, load research, contracts and special rate studies. In 1988 I transferred to the System Transactions Department, and was promoted to Manager - Interconnection Agreements in 1991. I assumed my present position in 1997.

Q. What are your duties and responsibilities as Manager - Contracts and Regulatory Support?

A. In my present position I am responsible for coordinating the development and implementation of transmission, interconnection and related agreements, and the AEP Companies Open Access Transmission Tariff (OATT). I also am responsible for the development of pricing studies for transmission and ancillary services and for the development and coordination of regulatory filings made to gain Federal Energy Regulatory Commission (FERC) acceptance of the rates, terms and conditions of the OATT, interconnection and other agreements.

Q. Do you hold any professional licenses?

A. Yes, I am registered as a Professional Engineer in the States of Indiana and Ohio.

Q. Have you previously testified on electric rate issues before any utility regulatory commissions?

A. Yes, I have presented testimony on various cost-of-service and rate design issues before the utility regulatory commissions of Kentucky, Michigan, Ohio, West Virginia, and Tennessee. I have also testified before the FERC in two cases involving transmission and ancillary services -- FERC Docket Nos. ER93-540-000 and ER98-2786-000.

Purpose of Testimony

Q. What is the purpose of your testimony in this proceeding?

A. My testimony in this proceeding describes how Columbus Southern Power Company and Ohio Power Company (CSP, OPCO or the Company) plan to meet the transmission and ancillary services needs of retail consumers who choose an alternative supplier of energy. I also discuss and support a method of calculation of the portions of CSP's and OPCO's revenue which will be satisfied by the AEP OATT, if all retail customers took service under that tariff.

List of Exhibits

Q. What exhibits are you sponsoring in this proceeding?

A. I am sponsoring the following exhibits for CSP and OPCO:

Description

EXHIBIT NO. ___ DWB-1, AEP Companies' Term Sheet on Settlement Rates, Per Stipulation by Applicants and FERC Staff, Docket No. ER98-2786-000

EXHIBIT NO. ___ DWB-2, CSP's Estimated OATT Revenues

EXHIBIT NO. ___ DWB-3, OPCO's Estimated OATT Revenues

Q. Were these exhibits prepared by you or under your supervision?

A. Yes.

Transmission Revenues

Q. What transmission rates are being used for the determination of OATT revenues?

A. The revenues are based on a settlement, in the form of a Stipulation, signed by AEP and the FERC Litigation Staff in FERC Docket No. ER98-2786-000. The Stipulation, among other things, specifies settlement rates for transmission and ancillary service that will result in reductions in the rates for transmission service under the OATT.

Q. Why do you believe the ER98-2786-000 stipulation rates are the appropriate rates to use?

A. The rates contained in the Stipulation represent the best measure of the rates and charges that will be applicable at the beginning of the Market Development Period (i.e., January 1, 2001). I have prepared a summary of the AEP's OATT prices contained in the Stipulation. That summary has been incorporated in my testimony as EXHIBIT NO. ___ DWB-1.

Q. What is your recommendation regarding how the Commission can determine the amount of revenue that will be realized from Ohio customers through application of the OATT?

A. In my opinion, the most straight forward and accurate way to calculate the amount of revenue to be realized from Ohio customers under the OATT is to apply the Stipulation pricing of Network Integration Transmission Service (NTS) to the aggregate load of each Ohio Company. The OATT offers two forms of transmission service, NTS and Point-to-Point (PTP) transmission. PTP service requires a separate transmission capacity reservation in whole megawatts (MW) for each transaction, consisting of a designated point of receipt (POR) and point of delivery (POD). PODs within the AEP control area can be aggregated for PTP service under the OATT, making it possible to include any number of consumers under a reservation, but NTS is the practical choice in most cases for retail access. Under NTS, an electric supplier will be charged for transmission service based on the aggregate load of the consumers that name that electric supplier as their supplier each billing period, measured after the fact. The electric supplier can arrange schedules for hourly energy receipts at any POR that has available transmission capacity (ATC), without the need to make and pay for specific capacity reservations. Charges for PTP service are based on the amount of capacity reserved before the fact. Before the fact reservations require the electric supplier to estimate the maximum amount of power that its customers will need, and pay for that amount whether the load actually reaches that level or not. In addition, if the load exceeds the reserved capacity, a penalty of up to 100% of the applicable rate may be assessed. For these reasons, I anticipate that NTS will be the transmission service of choice for retail access suppliers and customers.

Q. If some electric suppliers and/or consumers do elect to use PTP transmission service, will an estimate of transmission service revenues based on NTS still be accurate?

A. Yes. Experience leads me to believe that the only electric suppliers and consumers that will rely on PTP transmission will be those that can accurately forecast their capacity requirements, have generation behind the meter and/or plan to receive all or most of their supplies from a small number of sources. The advantages of NTS are less important to those customers. In any case, since the rate for firm PTP transmission is based on the same revenue requirement as is the NTS rate, the difference in charges for such customers compared to NTS service will be minimal.

Q. Have you prepared an estimate of the revenue that may be realized from Ohio customers under the OATT, using the NTS rate contained in the Stipulation?

A. Yes, see EXHIBIT NOS. ____ DWB-2 and 3, each consisting of two pages.

Q. Please describe EXHIBIT NO. ____ DWB-2 for CSP.

A. During CSP's test year for its last retail rate case the CSP retail load represented 12.45% of the AEP total transmission load, and, under the OATT would be responsible for $43,555,911 of the AEP System transmission revenue requirement. Page 1 of this exhibit shows, in Column 1, the 12-month average CSP load coincident to the AEP System transmission firm peak loads. Column 2 shows the portion of the AEP System transmission revenue requirement associated with the CSP loads. Under NTS, customers are charged for transmission service based on their Load Ratio Share (LRS). Referring to page 2 of this Exhibit, the CSP coincident load (2,273 MW) was determined by multiplying the total CSP load coincident to the AEP System firm peak demands (2,405 MW) by the CSP retail load responsibility factor (94.5149%) as used in

Case No. 91-418-EL-AIR. The CSP load ratio share, 0.1245 to be precise, was determined by dividing CSP's coincident load by the total AEP System 12-month average firm load (18,250 MW).

Individual class loads, and, in turn, their transmission revenue responsibilities, were derived based on load research information. As shown on Page 2 of EXHIBIT NO. ___ DWB-2, class load research, adjusted for losses, resulted in a total CSP load coincident to the AEP System peaks of 2,215,174 kW. The load research derived class loads were adjusted uniformly to match the 2,273,000 kW total derived from the total CSP load and the CSP retail allocation factor.

Q. Please describe EXHIBIT NO. ____ DWB-3 for OPCO.

A. During OPCO's test year for its last retail rate case the OPCO retail load represented 18.59% of the AEP total transmission load, and, under the OATT would be responsible for $65,017,387 of the AEP System transmission revenue requirement. Page 1 of this exhibit shows, in Column 1, the 12-month average OPCO load coincident to the AEP System transmission firm peak loads. Column 2 shows the portion of the AEP System transmission revenue requirement associated with the OPCO loads. Under NTS, customers are charged for transmission service based on their Load Ratio Share (LRS). Referring to page 2 of this exhibit, the OPCO coincident load (3,604 MW) was determined by multiplying the total OPCO load coincident to the AEP System firm peak demands (4,896 MW) by the OPCO retail load responsibility factor (73.6038%) as used in Case No. 94-996-EL-AIR. The OPCO load ratio share, 0.1859 to be precise, was determined by dividing the OPCO coincident load by the total AEP System 12-month average firm load (19,385 MW).

Individual class loads, and, in turn, their transmission revenue responsibilities, were derived based on load research information. As shown on Page 2 of this exhibit, class load research, adjusted for losses, resulted in a total OPCO load coincident to the AEP System peaks of 3,473,222 kW. The load research derived class loads were adjusted uniformly to match the 3,604,000 kW total derived from the total OPCO load and the OPCO retail allocation factor.

Ancillary Service Revenues

Q. Have you also prepared estimates of the revenue associated with retail customer's usage of ancillary services?

A. Yes, I have. Columns 3 and 4 of page 1 of EXHIBIT NOS. ___ DWB-2 and 3 show these calculations for the five ancillary services that are applicable. Under the Stipulation these five services will be provided at a combined rate of $342.71 per MW per month ($0.34271 kW-month).

Q. What are the five ancillary services?

A. The five ancillary services are: Scheduling, System Control and Dispatch Service (OATT Schedule 1), Reactive Supply and Voltage Control from Generation Sources Service (Schedule 2), Regulation and Frequency Response Service (Schedule 3), Operating Reserves – Spinning Reserves Service

(Schedule 5), and Operating Reserves – Supplemental Reserves Service (Schedule 6).

Q. What do CSP and OPCO propose in regard to service should an electric supplier fail to deliver sufficient power to serve its customers?

A. CSP and OPCO will provide Energy Imbalance Service under the provisions of Schedule 4 of the AEP OATT.

Q. Please describe how the OATT handles energy imbalance.

A. Energy imbalance within the FERC specified deadband is returned in kind. Energy imbalance outside the deadband is cash settled. Presently, AEP's OATT has a charge of $100/MWh for all Excess Energy Imbalance, i.e. load in excess of the sum of deliveries and deadband. When that rate was adopted, it was the highest rate the FERC permitted electric utilities to charge. With the advent of market pricing, AEP may incur substantially higher costs to supply energy not delivered by an electric supplier. To correct this deficiency, in FERC Docket No. ER98-2786-000, AEP has proposed a charge for Excess Energy Imbalance equal to the greater of (1) $100/MWh, (2) 110% of AEP's incremental cost of generation, or (3) 110% of AEP's incremental cost to purchase power.

Q. How are excess deliveries cash settled?

A. AEP gives transmission customers cash credits for excess deliveries outside the deadband, based on decremental costs, i.e. the cost AEP avoids by using the customer's excess energy rather than generating a like amount of power.

Q. Have you included any costs or revenues for Energy Imbalance Service in your EXHIBIT NOS. ___ DWB-2 and 3?

A. No. The Company does not expect significant net revenues under the OATT for Energy Imbalance Service. Most energy imbalance falls within the deadband and is handled by return-in-kind, resulting in no revenue to the Company. Further, the Excess Energy Imbalance charges proposed by the Company will foster good scheduling techniques by customers, and produce little, if any, net revenue to the Company. Finally, the existing retail bundled rates of CSP and OPCO do not include charges for this service, so there are no costs to unbundle.

Q. Does AEP plan to propose changes to the OATT to accommodate competition in retail electric sales?

A. At this time AEP has not identified any changes that are required for retail access, and as a result does not plan any changes for that purpose. AEP does anticipate; however, that a simplified energy imbalance service will be proposed at some point in the next few years. Cash settlement of all energy imbalance would be simpler and more commercially desirable than the present hybrid return-in-kind/cash settlement procedures. Unfortunately, the present lack of a reliable hourly energy market price standard for Ohio or the relevant market area severely limits the attractiveness of that option.

Q. Are any of the rates for transmission and ancillary services reflected in your EXHIBIT NOS. ___ DWB-1, 2 AND 3 subject to refund? If so, how will the Companies address refunds for transmission service provided for retail purposes?

A. As noted earlier in my testimony, the rates I have relied on are not presently in effect, but are the Companies' best estimate of the rates that will be in effect when retail access begins in Ohio. If the transmission or ancillary service rates then effective are different, the Company will file revised unbundled rates. If the FERC directs AEP to make refunds subsequent to the start of retail access, AEP will do so consistent with the order of the FERC requiring them.

Q. Does this conclude your direct testimony?

A. Yes.

AEP Companies'
Term Sheet on Settlement Rates
Per Stipulation by Applicants and FERC Staff
Docket No. ER98-2786-000

Service Description	Transmission Service	Scheduling Schedule 1	Reactive Supply Schedule 2	Regulation Service Schedule 3	Spinning Reserves Schedule 5	Supplemental Reserves Schedule 6
Net Annual Revenue Requirement	$349,712,000	$14,212,588	$17,978,148			
Monthly Service Rate $/MW-Mo.	1,420.00	57.71	73.00	53.00	79.50	79.50
Weekly Service Rate $/MW-Wk	326.79	13.28	16.80	12.20	18.30	18.30
Daily On-Peak Service Rate $/MW-Day	65.36	1.89	3.36	2.44	3.66	3.66
Hourly On-Peak Service Rate $/MWh	4.09	0.08	0.21	0.15	0.23	0.23
Daily Off-Peak Service Rate $/MW-Day	46.68	1.89	2.40	1.74	2.61	2.61
Hourly Off-Peak Service Rate $/MWh	1.95	0.08	0.10	0.07	0.11	0.11
Cost of Generating Capacity $/MW-Mo.				5,300.00	5,300.00	5,300.00
Requirement per MW of load (1)				1.0%	1.5%	1.5%

EXHIBIT NO. ____ DWB-1
Page 1 of 1

Columbus Southern Power Company
Estimated OATT Revenues
3 Months Actual, 9 Months Forecasted, Twelve Months Ended December 31, 1991

	Transmission Revenues		Ancillary Services Revenue	
	(1)	(2)	(3)	(4)
Customer Class	Average Monthly Loss-Adj. Demands at times of AEP Monthly Peaks (kW)	Annual Estimated Revenues	Total Rate ($/MW-Mo.)	Annual Revenues ($)
RR	809,365	$15,509,296	342.71	$3,328,530
RR1	167,142	3,202,825	342.71	687,375
GS1	57,163	1,095,375	342.71	235,084
GS2	260,353	4,988,963	342.71	1,070,707
GS3	874,825	16,763,660	342.71	3,597,735
GS4	102,008	1,954,708	342.71	419,510
SL	666	12,762	342.71	2,739
AL	1,478	28,322	342.71	6,078
Total	2,273,000	$43,555,911		$9,347,758

Notes:

1. CSP Retail Estimated Total OATT Basic Transmission Revenues -

		Load Ratio Share
CSP Retail Avg. Monthly Load at times of AEP Peaks:	2,273,000	12.45%
AEP 12 CP Internal Avg. Monthly Peaks including long-term sales:	18,250,000	
OATT Total Annual Network Service Revenue Requirement:	$349,712,000	

Total AEP-CSP Retail Allocation:
$349,712,000 * 2,273,000 / 18,250,000 = $43,555,911

2. Ancillary Services ($/MW-month)

Schedule 1 - Scheduling	$57.71
Schedule 2 - Reactive Power	73.00
Schedule 3 - Regulation Service	53.00
Schedule 5 - Spinning Reserves	79.50
Schedule 6 - Supplemental Reserves	79.50
Total	$342.71

Columbus Southern Power Company
Customer Class OATT Demands
3 Months Actual, 9 Months Forecasted, Twelve Months Ended December 31, 1991

AEP Internal Peaks and CSP Coincident Loads

Month	Date	Hour	AEP Internal Peak Load (MW)	CSP Internal Load (MW)
Jan	25	9	16,125	2,275
Feb	15	19	15,969	2,317
Mar	4	11	14,732	2,105
Apr	22	10	13,298	1,844
May	29	13	16,356	2,703
Jun	21	14	16,036	2,663
Jul	22	16	17,556	3,005
Aug	29	14	17,127	2,842
Sep	16	14	16,650	2,807
Oct	17	8	13,571	1,880
Nov	26	8	15,472	2,154
Dec	19	8	16,538	2,259
Total			189,430	28,854
Average			15,786	2,405
Long Term Firm Power Sales & Transmission Reservations			2,464	
Total Firm Transmission			18,250	
CSP Retail Allocation				94.5149%
CSP Retail MW				2,273

AEP-CSP Retail Class Demands

Customer Class	Class Loss-Adj. Demands Avg. Monthly LR demand at times of AEP Monthly Peaks (kW)	Adjusted Demands Adjusted to CSP Metered (kW)
RR	788,774	809,365
RR1	162,890	167,142
GS1	55,709	57,163
GS2	253,730	260,353
GS3	852,569	874,825
GS4	99,413	102,008
SL	649	666
AL	1,440	1,478
Total	2,215,174	2,273,000

Notes:
1. CSP load is at times of AEP Internal load peaks.
2. CSP Retail Allocation based on 3/9 Update Jurisdictional Study from Case No. 91-418-EL-AIR
3. Class demands based on post-migration load research.
4. Load research demands are average monthly class demands at hours of AEP internal peaks. Class demands are adjusted to AEP metered.

Ohio Power Company
Estimated OATT Revenues
3 Months Actual, 9 Months Forecasted, Twelve Months Ended March 31, 1995

	Transmission Revenues		Ancillary Services Revenues	
	(1)	(2)	(3)	(4)
Customer Class	Average Monthly Loss-Adj. Demands at times of AEP Monthly Peaks (kW)	Annual Estimated Revenues ($)	Total Rate ($/MW-Mo.)	Annual Revenues ($)
RS	1,106,523	$19,962,053	342.71	$4,550,598
GS1	55,716	1,005,136	342.71	229,133
GS2	462,722	8,347,662	342.71	1,902,953
GS3	965,048	17,409,794	342.71	3,968,779
GS4	942,511	17,003,219	342.71	3,876,095
EHG	18,811	339,357	342.71	77,361
EHS	680	12,267	342.71	2,797
SS	49,290	889,208	342.71	202,706
OL	1,086	19,592	342.71	4,466
SL	1,613	29,099	342.71	6,633
Total	3,604,000	$65,017,387		$14,821,521

Notes:

1. OPCo Retail Estimated Total OATT Basic Transmission Revenues -

		Load Ratio Share
OPCo Retail Avg. Monthly Load at times of AEP Peaks:	3,604,000	18.59%
AEP 12 CP Internal Avg. Monthly Peaks including long-term sales:	19,385,000	
OATT Total Annual Network Service Revenue Requirement:	$349,712,000	

Total AEP-OPCo Retail Allocation:
$349,712,000 * 3,604,000 / 19,385,000 = $65,017,387

2. Ancillary Services ($/MW-month)

Schedule 1 - Scheduling	$57.71
Schedule 2 - Reactive Power	73.00
Schedule 3 - Regulation Service	53.00
Schedule 5 - Spinning Reserves	79.50
Schedule 6 - Supplemental Reserves	79.50
Total	$342.71

Ohio Power Company
Customer Class OATT Demands
3 Months Actual, 9 Months Forecasted, Twelve Months Ended March 31, 1995

AEP Internal Peaks and OPCo Coincident Loads

Month	Date	Hour	AEP Internal Monthly Peak (MW)	OPCo Internal Load (MW)
Apr	8	8	14,630	4,511
May	31	14	14,570	4,576
Jun	20	14	18,070	5,255
Jul	20	15	17,959	5,284
Aug	25	16	16,588	5,056
Sep	15	16	16,489	5,034
Oct	28	8	14,354	4,392
Nov	30	8	15,292	4,593
Dec	13	8	16,405	4,885
Jan	5	8	18,342	5,115
Feb	9	8	18,633	5,132
Mar	10	8	16,593	4,921
Total			197,925	58,754
Average			16,494	4,896
Long Term Firm Power Sales & Transmission Reservations			2,891	
Total Firm Transmission			19,385	
OPCo Retail Allocation				73.6038%
OPCo Retail MW				3,604

AEP-OPCo Retail Class Demands

Customer Class	Class Loss-Adj. Demands: Avg. Monthly LR demand at times of AEP Monthly Peaks (kW)	Adjusted Demands: Adjusted to OPCo Metered (kW)
RS	1,066,373	1,106,523
GS1	53,694	55,716
GS2	445,931	462,722
GS3	930,029	965,048
GS4	908,310	942,511
EHG	18,128	18,811
EHS	655	680
SS	47,501	49,290
OL	1,047	1,086
SL	1,554	1,613
Total	3,473,222	3,604,000

Notes:
1. OPCo load is at times of AEP Internal load peaks.
2. OPCo Retail Allocation based on 3/9 Update Jurisdictional Study from Case No. 94-996-EL-AIR.
3. Class demands based on post-migration load research.
4. Load research demands are average monthly class demands at hours of AEP internal peaks.
   Class demands are adjusted to AEP metered.

Columbus Southern Power Company
Jurisdictional Allocation Factor
Twelve Months Ended December 31, 1991
3 Months Actual, 9 Months Forecasted

Description	MW	Source (MW)
Jan '91 - Actual	2,289	WPB-6.1l (u1)
Feb '91 - Actual	2,333	WPB-6.1l (u1)
Mar '91 - Actual	2,105	WPB-6.1l (u1)
Apr '91 - Estimated	2,029	WPB-6.1m
May '91 - Estimated	2,128	WPB-6.1m
Jun '91 - Estimated	2,753	WPB-6.1m
Jul '91 - Estimated	2,935	WPB-6.1m
Aug '91 - Estimated	2,935	WPB-6.1m
Sep '91 - Estimated	2,577	WPB-6.1m
Oct '91 - Estimated	1,988	WPB-6.1m
Nov '91 - Estimated	2,123	WPB-6.1m
Dec '91 - Estimated	2,410	WPB-6.1m
Average (Internal Load)	2,384	
Retail Coincident Demand Adjusted to Generation Level	2,253	3/9 Update Schedule B-6.1, page 1
Jurisdictional Allocation Factor	94.5149%	

Columbus Southern Power Company
Load Research Year Ended September 30, 1990
Coincident Peak Loads
Generation Levels

Pre-rate restructuring loss adjusted data

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Average
RR	928,172	965,597	837,673	546,403	342,686	758,338	1,124,816	1,055,353	923,638	529,410	647,894	805,304	788,774
RR1	210,550	164,777	141,576	116,571	70,638	189,850	216,704	213,199	145,724	121,086	169,704	194,296	162,890
GS1	193,593	201,414	166,713	252,766	254,865	329,834	373,579	340,581	342,210	247,704	183,300	231,977	259,795
GS1-NM-Fixed	1,987	2,172	1,978	2,041	1,970	2,064	2,021	2,012	2,069	1,974	2,041	1,986	2,026
GS1-NM-Other	624	0	0	0	0	0	0	0	0	0	663	0	107
GS2	476,029	479,892	436,143	491,645	572,087	663,075	706,095	644,268	634,937	528,506	455,425	523,975	551,006
GS3	301,439	310,812	323,457	346,022	380,214	409,441	411,040	377,304	379,173	331,350	304,006	314,631	349,074
GS4-Subtran	30,746	31,921	25,627	38,500	44,894	50,846	53,110	46,034	45,539	40,776	45,509	27,410	40,076
GS4-Tran	36,259	53,494	48,855	43,782	40,085	42,289	37,181	33,755	37,563	34,497	34,077	37,509	40,111
GS4-LSII	1,727	2,663	2,218	6,978	9,403	12,516	14,630	23,257	33,121	40,916	42,285	40,998	19,226
SL	2,522	0	0	0	0	0	0	0	0	0	3,176	0	475
SL-Energy	961	0	0	0	0	0	0	0	0	0	1,124	0	174
AL	8,241	0	0	0	0	0	0	0	0	0	9,033	0	1,440
TOTAL	2,194,850	2,212,742	1,983,240	1,844,708	1,716,822	2,458,253	2,939,176	2,735,763	2,543,974	1,876,219	1,898,237	2,178,086	2,215,174
DATE	12	26	1	3	16	18	9	28	6	20	29	22	
HOUR	19	8	8	10	13	14	14	15	16	10	19	10	

Post-rate restructuring metered data

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Average
GS1 Sec	35,263	34,757	29,289	42,514	36,463	59,606	70,961	62,125	64,910	41,769	34,539	38,568	45,897
GS2 Sec.	150,211	170,640	146,507	209,623	223,291	264,582	297,148	256,362	260,013	202,575	142,877	189,488	209,443
GS3 Sec	406,771	382,585	370,958	396,024	448,361	507,606	533,449	498,988	488,872	407,334	393,013	423,120	439,256
GS2 Pri	6,184	7,065	6,792	10,133	10,937	12,176	12,479	11,002	11,399	9,487	6,521	8,250	9,369
GS3 Pri	301,554	301,377	303,570	330,355	369,368	404,915	404,429	379,801	385,747	323,914	306,984	319,553	344,297

Columbus Southern Power Company
Load Research Year Ended September 30, 1990
Coincident Peak Loads
Generation Levels

Pre Rate Restructuring Class Totals

	Loss Adj
GS1 Sec	259,795
GS2 Sec	551,006
Total Sec	810,801
GS3 Pri	349,074

Post Rate Restructuring Class Totals

	Metered	Adjusted
GS1	45,897	53,576
GS2	209,443	244,483
GS3	439,256	512,742
Total Sec	694,596	810,801
GS2	9,369	9,247
GS3	344,297	339,827
Total Pri	353,666	349,074

Post Rate Restructuring Summary

Customer Class	Average Coincident Peak Demand
RR	788,774
RR1	162,890
GS1	53,576
GS1-NM-Fixed	2,026
GS1-NM-Other	107
GS2 Sec	244,483
GS2 Pri	9,247
GS3 Sec	512,742
GS3 Pri	339,827
GS4-Subtran	40,076
GS4-Tran	40,111
GS4-LSII	19,226
SL	475
SL-Energy	174
AL	1,440
Total	2,215,174

Columbus Southern Power Company
Load Research Year Ended September 30, 1990
Coincident Peak Loads
Generation Levels

Derivation of LS II Load Research

Three Month Actuals

	Jan	Feb	Mar
LS II Metered Actual	1,693	2,611	2,177
Loss Factors	1.01997	1.0201	1.01862
Loss Adjusted CP	1,727	2,663	2,218
DATE	25	15	4
HOUR	9	19	11

Nine Month Estimated (Customers used as a proxy for LS II)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Average
I/N Tek - CP	5,509	6,067	12,521	5,084	10,376	14,733	11,349	11,444	13,750	2,599	3,270	5,642	8,529
I/N Tek - NCP	8,940	18,050	19,325	18,872	18,248	20,960	19,911	19,146	18,050	3,563	4,101	9,696	14,905
												Ratio:	0.5722
Wheeling Pitt - CP	11,352	4,872	9,120	7,320	11,184	10,680	8,760	10,728	10,992	11,112	11,808	4,152	9,340
Wheeling Pitt - NCP	12,072	12,000	12,120	11,904	11,544	11,712	12,048	12,576	12,338	12,192	12,168	12,168	12,070
												Ratio:	0.7738
												Average:	0.6730
DATE	12	26	1	3	16	18	9	28	6	20	29	22	
HOUR	19	8	8	10	13	14	14	15	16	10	19	10	

Calculation of LS-II Loss Adjusted CP's

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Average
LS II - NCP				10,185	13,740	18,210	21,207	33,752	48,148	59,737	61,728	59,737	
LS II - CP (NCP x Ratio)				6,855	9,247	12,256	14,273	22,716	32,405	40,204	41,544	40,204	
Loss Factors				1.01797	1.01685	1.02123	1.025	1.02384	1.02212	1.0177	1.01783	1.01973	
Loss Adjusted CP				6,978	9,403	12,516	14,630	23,257	33,121	40,916	42,285	40,998	
LS II CP Summary	1,727	2,663	2,218	6,978	9,403	12,516	14,630	23,257	33,121	40,916	42,285	40,998	19,226

Ohio Power Company
Jurisdictional Allocation Factor
Twelve Months Ended March 31, 1995
3 Months Actual, 9 Months Forecasted

Description	MW	Source (MW)
Maximum Load	5,725	WPB-7.1a/u
System Sales & Losses	622	WPB-7.1a/u
Internal Load	5,103	
Retail Coincident Demand Adjusted to Generation Level	3,756	3/9 Update Schedule B-7.1, page 1
Jurisdictional Allocation Factor	73.6038%	

Ohio Power Company
Load Research Year Ended December 31, 1993
Coincident Peak Loads
Generation Level

Pre-rate restructuring loss adjusted data

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Average
RS	1,265,836	1,308,191	1,161,165	820,784	667,538	1,045,795	1,200,920	1,246,910	1,007,175	763,527	970,518	1,338,111	1,066,373
GSN	39,472	41,930	31,297	53,981	50,086	49,857	73,930	52,135	55,713	51,665	36,801	40,618	48,124
GSD Sec	371,074	363,099	319,017	420,972	539,694	493,936	535,897	468,817	531,967	387,741	380,593	338,819	429,302
GSD Pri	23,482	20,966	14,709	22,429	26,557	21,812	24,652	25,845	26,441	27,144	28,510	11,362	22,826
GSD Subtran	16,870	14,031	8,439	11,370	8,895	6,727	5,801	7,374	6,095	6,891	7,562	2,916	8,581
LP Sec	362,225	384,858	348,273	362,268	434,432	446,053	444,855	424,362	419,992	355,845	376,207	371,994	394,264
LP Pri	351,057	350,351	331,751	337,080	398,610	367,800	374,680	384,960	355,681	328,059	358,705	301,896	353,384
LP Subtran	173,720	195,651	167,234	173,922	192,646	163,799	159,592	171,117	174,738	182,294	171,468	151,895	173,173
IP Pri	37,510	36,324	33,141	34,470	38,943	31,993	36,047	39,249	37,108	34,338	33,863	31,906	35,408
IP Subtran	378,266	392,128	360,539	346,171	401,109	335,436	366,044	358,716	360,727	367,926	341,295	355,639	363,666
IP Tran	530,180	549,367	542,704	486,785	502,280	517,642	440,590	466,090	515,697	498,359	553,487	507,656	509,236
EHG	20,454	26,214	24,335	19,101	21,516	20,082	14,133	15,536	15,858	11,738	13,722	14,848	18,128
EHS	1,449	1,420	1,680	247	588	159	199	116	219	628	808	352	655
SS	66,520	72,581	50,495	63,511	55,619	27,453	30,322	33,564	40,189	39,313	62,326	28,116	47,501
OL	0	0	0	0	0	0	0	0	0	0	0	12,563	1,047
SL	0	0	0	0	0	0	0	0	0	0	0	18,642	1,554
TOTAL	3,638,115	3,757,111	3,394,779	3,153,091	3,338,513	3,528,544	3,707,662	3,694,791	3,547,580	3,055,268	3,335,865	3,527,333	3,473,222
DATE	26	19	15	5	11	18	28	30	2	29	8	21	
HOUR	8	8	8	11	14	14	15	15	15	8	9	19	

Post-rate restructuring metered data

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Average
GS1 Sec	46,675	46,800	35,667	59,048	55,581	57,684	81,851	65,066	65,683	48,879	37,741	43,562	53,686
GS2 Sec	332,453	349,195	307,769	375,449	484,707	419,560	416,273	378,814	433,872	306,063	332,420	284,456	368,419
GS3 Sec	395,534	412,986	361,234	420,519	489,685	492,023	551,291	504,616	520,180	408,475	405,871	431,075	449,457
GS2 Pri	47,855	47,749	40,611	52,916	48,849	45,372	43,670	44,968	41,534	51,445	49,268	27,662	45,158
GS3 Pri	329,885	336,034	315,862	311,918	362,757	338,673	346,843	358,765	337,832	307,499	331,429	296,121	331,135
GS2 Subtran	32,656	34,697	29,906	37,610	34,519	34,207	32,009	33,261	31,223	37,019	36,587	19,932	32,802
GS3 Subtran	155,930	174,705	145,852	154,641	166,437	142,324	137,622	147,713	152,036	157,494	152,430	133,421	151,717