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FILE

EXHIBIT NO. ________

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Columbus Southern Power Company for Approval of its Electric Security Plan; an Amendment to its Corporate Separation Plan; and the Sale or Transfer of Certain Generating Assets	Case No. 08- 917-EL-~~UNC~~ SSO
and	
In the Matter of the Application of Ohio Power Company for Approval of its Electric Security Plan; and an Amendment to its Corporate Separation Plan	Case No. 08- 918-EL-~~UNC~~ SSO

DIRECT TESTIMONY
OF
LEONARD V. ASSANTE
ON BEHALF OF
COLUMBUS SOUTHERN POWER COMPANY
AND
OHIO POWER COMPANY

Filed: July 31, 2008

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LEONARD V. ASSANTE
CASE NO. 08-917-EL-UNC
CASE NO. 08-918-EL-UNC

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CASE NO. 08-917-EL-UNC
CASE NO. 08-918-EL-UNC

INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Leonard V. Assante and my business address is 1 Riverside Plaza Columbus, Ohio 43215.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am testifying on behalf of Columbus Southern Power Company (CSP) and Ohio Power Company (OPCo) or collectively the (Companies).

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by American Electric Power Service Corporation (AEPSC), a subsidiary of American Electric Power Company, Inc. (AEP), as Vice President of Regulatory Accounting Services.

Q. WHAT ARE YOUR PRINCIPAL RESPONSIBILITIES AND DUTIES AS AEPSC'S VICE PRESIDENT OF REGULATORY ACCOUNTING SERVICES?

A. I am responsible for providing regulatory accounting expertise and support to AEPSC and the AEP Electric Operating Subsidiaries' Regulatory management/staff and to the Controller and the Assistant Controllers of the AEP

Electric Operating Subsidiaries. My staff and I participate in the development of regulatory strategy and in the development and preparation of regulatory filings and in the resultant regulatory proceedings as expert regulatory accounting witnesses. We monitor regulatory developments by reading regulatory statutes, rulemakings, testimony, settlement agreements and orders to determine their regulatory accounting and financial reporting implications and direct the development of the appropriate regulatory accounting and financial disclosures, as required by such regulatory developments across the AEP System.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I graduated magna cum laude from Pace University with a Bachelor of Business Administration in Accountancy Practice in June of 1967. I was awarded a certificate of Certified Public Accountant by the state of New York in 1970 while a member of the audit staff of Arthur Andersen & Company. I successfully completed an AEP management program at the University of Michigan Graduate School of Business Administration in 1977 and the American Institute of Certified Public Accountant's National Tax Education Program in 1978 also at the University of Michigan. I have been a member of the American Institute of Certified Public Accountants since becoming a Certified Public Accountant and have been an active member of the Edison Electric Institute's Accounting and Taxation Committees. Prior to AEP's merger with Central and South West Corporation and since joining AEP in 1971, I held various accounting and taxation positions with the American Electric Power System. Among those positions were Administrative Assistant to the Senior Vice President and Chief Accounting Officer, Senior Tax Accountant, Manager of Taxes and Assistant Treasurer, Director of Taxes and Assistant Treasurer, Director of Accounting Policy and Research and Assistant Controller, Controller of AEPSC and Vice President-Controller and Chief Accounting Officer of AEP, AEPSC and AEP's operating subsidiaries. Subsequent to the merger in 2000, I was appointed to my current position of Vice President of Regulatory Accounting Services. For the last seven years I have served as Chairman of the Edison Electric Institute's Federal Energy Regulatory Commission Accounting Liaison Committee. I have testified on behalf of the Edison Electric Institute and AEP before the Financial Accounting Standards Board (FASB) and on behalf of AEP's Electric Operating Companies in regulatory proceedings.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. Yes, I have testified for both CSP and OPCo.

Q. DID YOU TESTIFY IN THE COMPANIES' RATE STABILIZATION PLAN (RSP) CASE?

A. Yes I testified on behalf of the Companies in Case No. 04-169-EL-UNC, which approved the Companies' RSP.

<u>**PURPOSE OF TESTIMONY**</u>

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to describe and discuss the regulatory accounting and related requirements for the Companies' proposed phase-in of their recovery of fuel, purchased power and other variable production (Fuel Adjustment Clause or FAC) costs in 2009, 2010 and 2011 in excess of what is presently reflected in current Standard Service Offer (SSO) rates. I will also discuss the accounting for the Companies' proposed on-going annual FAC mechanism, described in the testimony of Companies' witness Mr. Nelson. In addition, I will discuss the proposed accounting to address, as Companies' witness Baker testifies, the possibility that generating units may have to be shut down early and the resultant ratemaking. I also support certain existing previously authorized regulatory asset deferrals that the Companies are proposing to amortize and recover beginning with the first billing cycle in 2011 and the resultant ratemaking/accounting. In addition I will discuss the accounting for CSP's planned gridSMART advanced metering program and for the Companies' planned Energy Efficiency and Demand Response (DSM) program costs. Finally, I will briefly discuss the Economic Development tracker and how it will be tracked and recovered.

<u>FAC PHASE-IN PLAN ACCOUNTING</u>

Q. PLEASE DESCRIBE THE COMPANIES' FAC PHASE-IN PROPOSAL.

A. As Companies' witnesses Mr. Hamrock and Mr. Baker testify, the Companies are requesting to make the ESP revenue requirement more affordable to ratepayers by phasing-in the Companies' proposed incremental FAC expenses during the three-year ESP period. In addition, as I discuss in my testimony and as Mr.

Nelson explains in his testimony, there will be a periodic on-going FAC cost true-up of 100% of the FAC cost recoveries plus the resultant current period FAC cost deferrals to 100% of the incremental FAC costs in 2009, 2010 and 2011, in order to adjust the estimated incremental FAC costs to actual FAC costs for the current period. This will produce on-going periodic under/over recoveries of FAC costs for the period. During the phase-in deferral period (2009 to 2011) FAC under/over recoveries will be included in the total FAC costs to be phased-in. The phase-in of incremental FAC cost recoveries will be over the three years ending with the completion of the last billing cycle in 2011. The phase-in will continue until the entire 2011 incremental FAC revenue requirement is implemented with the last billing cycle of 2011.

Q. HOW WILL THE COMPANIES ACCOUNT FOR THE UNRECOVERED FAC COSTS THAT RESULT FROM THE PHASE-IN PLAN IN 2009, 2010 AND 2011?

A. As a result of the phase-in, both CSP and OPCo are expected to under recover incremental incurred FAC costs in one or more of the ESP years of 2009, 2010 and 2011. The Companies are proposing to defer any unrecovered incremental FAC costs in 2009, 2010 and 2011 plus a carrying charge on the unrecovered deferrals, over ten years from 2009 to 2018 and recover the resultant regulatory assets over seven years from 2012 to 2018. The Companies are requesting that the Commission approve the proposed phase-in plan inclusive of the recovery of their phase-in regulatory assets through a non-bypassable FAC phase-in rider, which will remain in place from the last billing cycle in 2011.

Q. HOW WILL THE AMOUNT OF FAC COSTS TO BE DEFERRED BE DETERMINED IN 2009, 2010 AND 2011 UNDER THE COMPANIES' PROPOSED PHASE-IN PLAN?

A. Specifically, the proposed phase-in will be accomplished through the deferral of a sufficient amount of FAC costs not being recovered in current rates (incremental FAC costs) to bring the annual SSO rate increase in 2009, 2010 and 2011 for all classes of the Companies' customers to approximately 15% as discussed by witnesses Baker and Roush. The 2009 deferral cannot exceed the total incremental FAC costs, which is the excess of total 2009 FAC costs over the FAC costs presently reflected in the SSO rates at the end of 2008, which Mr. Roush estimates for 2009, the initial year of the phase-in. The incremental FAC costs to be phased-in starting in 2010 will also include under/over recovery adjustments from the normal on-going workings of a periodic FAC tracker true-up mechanism discussed in the next section of this testimony. Throughout the ESP period, the adjusted incremental FAC cost deferrals will be adjusted whenever necessary by Mr. Roush to maintain the annual percentage rate increase for each class of customer at approximately 15% throughout the three-year ESP period. Starting with 2012, annual incremental FAC costs will no longer be subject to phase-in deferrals and any incremental FAC under or over recovery determined for a period will be separately deferred for amortization and recovery over the next FAC period. That is, under/over recovery deferrals will not be part of the phase-in regulatory asset balance after 2011, which will be recovered over the proposed seven-year phase-in recovery period. See the next section of this testimony for details of the proposed FAC accounting post 2011.

Q. WHAT IS THE ESTIMATE OF THE TOTAL INCREMENTAL FAC COSTS FOR 2009 WHOSE RECOVERY WILL BE SUBJECT TO BEING PHASED-IN UNDER THE PROPOSED PHASE-IN PLAN?

A. Based on information supplied by Mr. Nelson, Mr. Roush estimates that CSP's and OPCo's incremental FAC costs subject to being phased-in in 2009 is $260 million and $367 million, respectively.

Q. DO THE COMPANIES HAVE AN ESTIMATE OF THE INCREMENTAL 2009 FAC COSTS TO BE DEFERRED UNDER THE PROPOSED PHASE-IN PLAN?

A. Yes. Mr. Roush estimates that initially in determining the 2009 SSO rates per customer class CSP and OPCo will need to defer approximately $112 million or 43% and $300 million or 82% of incremental 2009 FAC costs, respectively, in order to hold the initial 2009 SSO ESP percentage rate increase to approximately 15% for each class of their customers.

Q. PLEASE PROVIDE THE ESTIMATE FOR THE AMOUNT OF 2009 INCREMENTAL FAC COSTS THAT THE COMPANIES EXPECT TO RECOVER THROUGH THE PROPOSED FAC PHASE-IN RIDER.

A. Pending changes that may occur in 2009, with the exception of any changes in the Transmission Cost Recovery Rider, Mr. Roush informs me that the Companies presently estimate that the annual incremental FAC cost to be recovered in 2009 before any FAC under or over recovery adjustment at the end of 2009 is $148 million or 57% of total incremental FAC costs for CSP and $67 million or 18% of total incremental FAC costs for OPCo.

Q. UNDER THE COMPANIES' PROPOSED PHASE-IN, HOW WILL THE COMPANIES ADDRESS THEIR COST OF FINANCING THEIR UNRECOVERED PHASED-IN REGULATORY ASSETS?

A. To cover the cost of financing, the Companies are proposing a carrying cost on the unrecovered balance of the deferred incremental FAC costs at their weighted average cost of capital (WACC) rate over the entire ten-year phase-in plan period in order to recover the cost of financing their deferred unrecovered FAC costs. The Companies are proposing to use a 50/50 debt to equity ratio, actual debt costs and a return on equity (ROE) at 10.5% to compute the carrying cost WACC rate. Mr. Nelson supports the 50/50 capital structure assumption and the use of a 10.5% ROE rate, which is the equity cost rate approved in the PUCO orders during the RSP period for carrying cost WACC determinations. As such, it represents the Commission's carrying cost ROE rate assumption used in the recent PUCO orders for the Companies.

Q. HOW WILL THE ACTUAL PHASE-IN DEFERRAL IN 2009 BE RECOVERED UNDER THE COMPANIES' PHASE-IN PROPOSAL?

A. The actual resultant phase-in deferral of 2009 incremental FAC costs will be recovered, along with the incremental FAC cost deferrals in 2010 and 2011 and related carrying costs accrued on the unrecovered deferred balance from 2009 through 2018, over the proposed seven-year phase-in recovery period of 2012 to 2018. On a monthly basis in 2009, 2010 and 2011, the phase-in incremental FAC cost deferrals can be increased by any additional revenue requirement, which causes the annual percentage rate increase in 2009, 2010, and/or 2011 to exceed the approximately 15% increase for any customer class. Phase-in plan deferrals will be adjusted when this occurs in order to return to the limitation except for when the increase results from FERC initiated costs included in the Companies' Transmission Cost Recovery rider. In 2012, the incremental FAC cost phase-in deferrals will cease, the debt component of carrying cost phase-in deferrals will continue to be deferred monthly, the periodic under/ over recovery adjustments from the normal workings of the on-going periodic FAC true-up mechanism will be deferred and amortized commensurate with recovery in the next period's FAC rates, and the incremental 2012 FAC rate will be increased to recover the estimated change in FAC costs for 2012 plus the first years' straight-line recovery of the total deferred incremental FAC costs plus carrying costs there-on through 2018 under either another ESP or the non-market portion of a MRO. The 2012 increase will remain in place through the end of 2018 if nothing changes.

Q. WHY ARE A THREE-YEAR PHASE-IN DEFERRAL PERIOD AND A SEVEN-YEAR PHASE-IN RECOVERY PERIOD APPROPRIATE?

A. The Companies believe that a three-year deferral and seven-year recovery period are reasonable. Further, it supports a probability of recovery requirement in the applicable generally accepted accounting principles (GAAP). A significantly longer recovery period would increase the carrying costs to be paid by customers.

Q. PLEASE EXPLAIN THE BASIS FOR THE ACCOUNTING THAT WILL BE REQUIRED TO ACCOUNT FOR THE COMPANIES' PROPOSED ESP PHASE-IN PLAN.

A. If the PUCO approves the Companies' proposed phase-in plan, once the FAC costs are approved as prudently incurred costs in 2009, 2010 and 2011 FAC filings, the deferred portion of those prudently incurred costs will be recovered in the future from 2012 to 2018 without further adjudication. As a result, the unrecovered deferred incremental FAC costs have a future economic benefit to the Companies. In this connection, FASB Concept Statement No. 6 defines an asset as "...probable future economic benefits obtained or controlled by a particular entity as a result of a past transaction or event." The Statement goes on to state, in paragraph 26, that an asset "...embodies a probable future benefit that involves a capacity, singly or in combination with other assets, to contribute to future net cash inflows..." Based on this definition of an asset, it is clear, if the PUCO approves the future recovery in this ESP proceeding of the deferred incremental FAC costs without any required further adjudication, that the deferred amounts would qualify, in general, as an asset for accounting purposes. Regarding the type of asset, Paragraph 9 of Statement of Financial Accounting Standards (SFAS) No. 71, Accounting for the Effects of Certain Types of Regulation, requires that when incurred costs are probable of future recovery from inclusion of that cost in allowable future costs for ratemaking purposes, the unrecovered costs should be capitalized (deferred) as a regulatory asset. The Statement recognizes that a regulator can provide reasonable assurance of the existence of an asset, if the regulator provides for the future recovery through cost-based rates, of an incurred cost that would otherwise have been charged to expense. When that occurs, the regulator-created asset should be recorded by deferring the incurred cost to be recovered in the future. The deferral as a regulatory asset of unrecovered incurred costs to be recovered in the future allows the Companies to properly match costs with the revenues recovering said costs in the same accounting period. The matching of cost and revenue is a long-standing accounting concept, which produces meaningful financial statements especially for cost-based regulated operations. A reading of the applicable GAAP, therefore, supports the Companies' capitalization of incurred incremental deferred FAC costs not recoverable in 2009, 2010 and 2011 under the Companies' proposed phase-in plan as an asset, specifically a regulatory asset, to be recovered in the future (from 2012 to 2018) provided the PUCO approves a phase-in plan with appropriate explicit deferral and future recovery provisions.

Q. PLEASE EXPLAIN THE ACCOUNTING THE COMPANIES PROPOSE TO EMPLOY TO ACCOUNT FOR THE PROPOSED PHASE-IN OF INCREMENTAL FAC COSTS AND THE RECOVERY OF RESULTANT CARRYING COSTS.

A. A Commission order that establishes probability of recovery will permit the Companies to defer, as a regulatory asset, the unrecovered incremental FAC costs in 2009, 2010 and 2011 that result from the phase-in plus the debt component of a WACC on the unrecovered balance of the regulatory asset including the deferred carrying costs throughout the ten-year phase-in plan period. The equity component of the WACC is not deferrable due to paragraph 9 of SFAS 92, Regulated Enterprises, Accounting For Phase-in Plans, which prohibits the deferral of equity except during construction. Clearly, the phase-in of incremental FAC costs is not phasing in construction related costs and as such would not qualify the Companies to defer the equity portion of the carrying cost to be recovered in the future. As a result, the equity carrying costs will be recognized as income when collected (proposed for 2012 through 2018). The debt component of the carrying cost will be deferred from 2009 to 2018 as a phase-in regulatory asset and recognized as income to offset interest expense from the financing of the phase-in plan deferrals. The phase-in regulatory assets for both incremental unrecovered FAC costs and the debt component of the carrying cost will be amortized to expense commensurate with their recovery over the proposed seven-year phase-in recovery period from 2012 to 2018 with no earnings impact.

Q. **WHAT FERC ACCOUNTS WILL THE COMPANIES EMPLOY TO RECORD THE DEFERRALS AND THE AMORTIZATIONS DISCUSSED ABOVE?**

A. The Companies will defer the unrecovered incremental FAC costs resulting from the proposed phase-in plan in Account 182.3, Other Regulatory Assets, with a credit to fuel expense Account 501, Fuel. They will defer the debt component of the carrying cost in Account 182.3, Other Regulatory Assets, and credit Account 421, Miscellaneous Nonoperating Income. Account 421 as a below-the-line account as is the interest it will be recovering. ESP revenues generated by the proposed phase-in plan from 2012 to 2018 will be recorded in the appropriate

FERC revenue income Accounts 440 through 446 and will be heavily offset by the amortization of the phase-in plan deferrals being recovered in Account 182.3, Other Regulatory Assets, through a credit to such regulatory asset accounts and a charge to Account 501, Fuel, in the amount of the deferred recovered incremental FAC costs being recovered and a charge to Account 421, Miscellaneous Nonoperating Income, in the amount of the deferred debt carrying costs being recovered. The difference will represent the equity component of the carrying cost which will flow to earnings.

Q. ARE THE COMPANIES' GENERATION/SUPPLY BUSINESSES COST-BASED REGULATED?

A. No. With the passage of Ohio restructuring legislation back in 1999 the Companies' generation/supply businesses ceased the application of SFAS 71 regulatory accounting as a result of its expected transition under the law to market based rates in 2006.

Q. WHAT WERE THE ACCOUNTING CONSEQUENCES OF THE COMPANIES' GENERATION/SUPPLY BUSINESSES NO LONGER BEING COST-BASED REGULATED?

A. Through the workings of SFAS 101, Accounting for the Discontinuation of Application of SFAS 71, as interpreted by EITF 97-4, Deregulation of the Pricing of Electricity-Issues Related to the Application of FASB Statements No. 71 and 101, the Companies were required to cease practicing regulatory deferral accounting with the passage of legislation that transitioned them off of cost-based regulation. As a result, they could not record regulatory assets in their generation businesses with the exception of those related to any stranded cost recoveries.

Q. IF THE GENERATION/SUPPLY BUSINESSES OF THE COMPANIES ARE NO LONGER COST-BASED REGULATED, HOW CAN THE COMPANIES RECORD A REGULATORY ASSET UNDER SFAS 71 FOR THE PHASED-IN UNRECOVERED FAC COSTS?

A. SFAS 101, Accounting for the Discontinuation of Application of SFAS 71, states: "If a separable portion of the enterprise's operations within a regulatory jurisdiction ceases to meet the criteria for application of Statement 71, application of that Statement to that separable portion shall be discontinued. That situation creates a presumption that application of Statement 71 shall be discontinued for all of the enterprise's operations within that regulatory jurisdiction. That presumption can be overcome by establishing that the enterprise's other operations within that jurisdiction continue to meet the criteria for application of Statement 71." Therefore, the Companies have concluded, with their Independent Public Accountant's, Deloitte & Touche LLP's (D&T), concurrence, that the proposed implementation of a FAC establishes that the Companies' internal load fuel/purchased power operations within Ohio are returning to cost-based regulation and, as such, can re-apply SFAS 71 regulatory accounting. So if the Commission orders a FAC for the Companies with a phase-in of incremental FAC costs and the approving order meets the requirements of SFAS 71, their FAC operations can record regulatory asset deferrals. As a result, the Companies can record regulatory assets for any incurred FAC costs that are probable of future recovery including any incremental FAC costs in 2009, 2010 and 2011 that are not to be currently recovered under the Companies' proposed FAC phase-in plan that will probably be recoverable in the future through the operations of the Companies' proposed FAC phase-in plan and its FAC true-up mechanism; provided the Commission's order approving the FAC and the related FAC phase-in plan meets the requirements of SFAS 71.

Q. WHAT ARE THE REQUIREMENTS THAT SHOULD BE MET IN ORDER TO ENABLE THE COMPANIES TO OFFER A PHASE-IN PLAN AND PERFORM THE PROPOSED PHASE-IN FAC DEFERRAL ACCOUNTING?

A. Paragraph 9 of SFAS 71 requires that in order to record and maintain a regulatory asset, the deferred cost must be probable of recovery in future regulated rates. In order to satisfy the requirement, to demonstrate probability of recovery, the Companies believe and D&T concurs, that the PUCO order approving the ESP phase-in plan must provide assurance of probable future recovery of the deferred incremental FAC costs that will result from an approved incremental FAC phase-in plan. We discussed this matter with D&T and have concluded that probability of recovery can be supported if the PUCO's order approving a FAC and a related FAC phase-in plan were to provide for: explicit recovery of the deferred unrecovered incremental FAC costs and related carrying costs over the proposed recovery period through a non-bypassable rider, recovery over a fixed recovery period, not to significantly exceed the proposed seven-year phase-in recovery period, recovery on a straight-line or decreasing annual basis, i.e. the recovery should not be back-end loaded, and the unrecovered balance of the regulatory assets should earn a carrying cost if securitization is not feasible. In addition, in the first year of the recovery period, and every year thereafter, the order should provide for full recovery of the straight-line or declining deferral amortization plus that current year's FAC revenue requirement through a continuing functioning FAC mechanism. Also, the order should address how the deferred unrecovered incremental FAC costs in 2009, 2010 and 2011 will be treated in S.B.221's "significantly excessive earnings test" determination. If the PUCO's order in this proceeding explicitly complies with the proposed requirements, the Companies should be able to comply, with the probability of recovery requirement in SFAS 71. Absent establishing probability of recovery, the Companies cannot capitalize their unrecovered incremental FAC cost as a regulatory asset. If the regulatory asset deferrals cannot be recorded due to a failure to establish probability of recovery and the Companies borrow to pay for the unrecovered fuel cost, equity as a percentage of capitalization will decline significantly, forcing the Companies to issue costly equity significantly in excess of the return on the equity level being recovered in the requested carrying cost.

Q. WHY SHOULD THE COMMISSION'S ORDER ADDRESS HOW FAC COSTS, DEFERRED IN 2009, 2010 AND 2011 UNDER THE PROPOSED FAC PHASE-IN WILL BE INCLUDED IN DETERMINING EARNINGS FOR THE PURPOSE OF THE SIGNIFICANTLY EXCESSIVE EARNINGS TEST AND WHAT SHOULD IT SAY TO COMPLY WITH SFAS 71's PROBABILITY REQUIREMENT?

A. Failure to include the FAC costs deferred in the current year in the significantly excessive earnings test for that year could result in a refund which would effectively negate the purpose of the deferrals, making them subject to refund and, therefore, not probable of recovery in future cost-based regulated rates and, as such, not recordable/sustainable as a regulatory asset. Further, the deferrals do not represent earnings or cash revenues collected from ratepayers and, as such, should not result in a refund of earnings amounts not yet collected from ratepayers. The only earnings that result from the proposed phase-in plan is the equity component of the carrying cost which is not deferred and as such is automatically and appropriately included in the earnings test when collected in 2012 to 2018. The phase-in deferrals should be matched up with the revenues that recover those deferred costs and included in the earnings test only at the time of their amortization/recovery.

Q. WHY SHOULD THE PHASE-IN RIDER BE A NON-BYPASSABLE RIDER?

A. Recovery through a non-bypassable rider supports SFAS 71's probability of recovery requirement. Since ratepayers can switch suppliers, they can bypass the FAC phase-in rider by buying electricity from a supplier other than the Companies. This adversely impacts probability of recovery. Counsel has advised me that S.B. 221 provides for phase-in deferrals to be recovered on a non-bypassable basis.

Q. WHY SHOULD THE PHASE-IN RECOVERY PERIOD NOT BE SIGNIFICANTLY LONGER THAN THE SEVEN YEARS THE COMPANIES ARE PROPOSING?

A. Probability of recovery becomes an issue the longer the unsecured recovery period. Discussions with D&T suggest that the longer the recovery period, the more difficult it is to demonstrate probability of recovery. A recovery period significantly in excess of the seven-year period being proposed by the Companies would make it more difficult to conclude that recovery is probable.

Q. WHAT IS THE AMOUNT OF THE TOTAL INCREMENTAL FAC COST THAT WOULD BE SUBJECT TO BEING PHASED-IN UNDER THE COMPANIES' PROPOSED PHASE-IN PLAN?

A. Based on information provided to Mr. Roush by Mr. Nelson, Mr. Roush provided me with an estimate of the incremental 2009 FAC cost increase of $627 million ($260 million for CSP and $367 million for OPCo) that the Companies are proposing to phase-in over three years and recover over seven years. In addition, the debt component of the carrying cost would also be deferred over the entire ten-year phase-in plan period.

Q. WHAT IS THE AMOUNT OF SUCH TOTAL INCREMENTAL FAC COSTS THAT WILL BE DEFERRED IN 2009 UNDER THE COMPANIES' PROPOSED FAC PHASE-IN PLAN?

A. Mr. Roush provided me with an estimate for 2009 of $412 million ($112 million for CSP and $300 million for OPCo) that the Companies anticipate they will defer under the proposed phase-in plan.

Q. CAN YOU PROVIDE AN EXAMPLE OF WHAT THE PROPOSED PHASE-IN WOULD LOOK LIKE ASSUMING THAT THE ANNUAL INCREMENTAL FAC COSTS ARE UNCHANGED IN 2010 AND 2011?

A. Yes. See Exhibit LVA-1, which models a phase-in of annual $367 million for OPCo and $260 million for CSP of incremental FAC costs, by Company, during the three-year ESP period of 2009 through 2011 and the recovery of the resultant deferrals over the seven years from 2012 to 2018. The example uses the estimates of $112 million for CSP and $300 million for OPCO provided to me by Mr. Roush as the estimated amount of incremental FAC costs to be deferred in 2009 to comply with the approximately 15% rate increase limitation. Further, if 2010 and 2011 incremental FAC costs do not change from 2009, Mr. Roush estimates that CSP will not have to provide any deferrals in 2010 and 2011 and that OPCo will have to defer 38% of its 2010 incremental FAC costs in 2010 and none in 2011. I used these estimates provided by Mr. Roush to determine the 2010 and 2011 deferrals for CSP and OPCo in order not to exceed the approximately 15% rate increase limitation. For illustrative purposes, I also assumed that total incremental FAC costs subject to being phased-in in 2010 and 2011 will be the same as the above total in 2009 of $260 million for CSP and $367 million for OPCo, i.e., I assumed that incremental FAC costs would not increase or decrease from 2009 to 2010 and from 2010 to 2011. Further, I assumed that there would be no under or over recoveries under the FAC true-up mechanism in 2009, 2010 and 2011. The illustrative exhibit also assumes that the after tax carrying cost debt rate is 5.5% and that the ROE equity component of the carrying cost rate is 10.5%

after tax (16.8% before tax) throughout the ten-year (2009 to 2018) proposed phase-in plan period.

Q. CAN YOU SUMMARIZE WHAT THE ILLUSTRATIVE EXHIBIT LVA-1 SHOWS?

A. Yes. The exhibit illustrates under the above-stated assumptions that the proposed phase-in plan, based on estimated 2009 incremental FAC costs of $367 million for OPCo and of $260 million for CSP produces a total deferral for CSP of $146 million of incremental FAC costs and a total deferral for OPCo of $554 million of incremental FAC by the end of the three year deferral period. It also shows that the FAC revenue requirement being collected is $148 million for CSP, and $67 million for OPCo in 2009; $260 million for CSP and $228 million for OPCo in 2010; and $260 million for CSP and $367 million for OPCo in 2011. Carrying costs over the entire ten-year phase-in plan period total $99 million for CSP and $362 million for OPCo. The illustrative example also shows a phase-in annual revenue requirement increase in 2012 of $114 million for OPCo and $30 million for CSP to remain in place through 2018 to recover the total incremental FAC deferrals in 2009, 2010 and 2011 and the related carrying cost, both deferred (debt related) and not deferred (equity related). It should be noted that since the example on LVA-1 does not include any annual increase/decrease in incremental FAC costs, after 2009 or any true-up amounts, the total phase-in plan recoveries, deferrals and the related carrying cost total may be under or over-stated. The total FAC revenue requirement, which is also subject to change, including the total carrying cost is $879 million for CSP and $1.463 billion for OPCo over the entire ten-year phase-in period.

FAC TRACKER MECHANISM ACCOUNTING

Q. WHAT ARE THE COMPANIES PROPOSING REGARDING AN ON-GOING FUEL COST RECOVERY TRACKER MECHANISM?

A. The Companies are proposing an on-going FAC true-up cost recovery mechanism. In that regard, the Companies are proposing to implement a traditional fuel adjustment clause (FAC) mechanism, which will recover, beginning in January 2009, estimated incremental fuel costs and true-up of the recoveries to actual periodically. The Companies are proposing to adopt the period in the Commission's final rules, when issued, to adjust the recoveries on an estimated basis to actual incremental FAC costs. The tracker will be adjusted to comply with the rules ultimately adopted by the Commission.

Q. HOW DOES THE PHASE-IN PROPOSAL AFFECT THE PROPOSED ON-GOING FAC MECHANISM SPONSORED BY MR. NELSON?

A. As indicated in Section III of this testimony, the Companies are proposing to phase-in the amount of 2009, 2010 and 2011 (the three-year ESP period) FAC costs in excess of the level of FAC costs included in the pre-2009 SSO rates determined for 2009 by Mr. Nelson. The details of the proposed phase-in and the related accounting are discussed at length above. Regarding the on-going true-up of FAC costs, the Companies are proposing to employ traditional fuel clause under/over deferral true-up accounting starting in 2012. In the interim (2009 to

2011) the Companies are proposing to add periodic under recovery adjustments that may result from the periodic FAC true-up or deduct any over recovery from the total incremental FAC costs to be phased-in. Whether the under or over recovery will be collected or returned to customers or whether it will be deferred for recovery from 2012 to 2018 will be determined by the application of the approximately 15% rate increase limitation to the overall increase.

Q. PLEASE SPECIFICALLY EXPLAIN FOR THE RECORD WHAT YOU MEAN BY TRADITIONAL FUEL CLAUSE UNDER/OVER DEFERRAL TRUE-UP ACCOUNTING THAT THE COMPANIES WILL EMPLOY STARTING IN 2012.

A. Specifically, under traditional actual fuel clause true-up under/over recovery accounting, any under recovery would be deferred in Account 182.3, Other Regulatory Assets, and recovered through fuel rates over the next fuel clause period. The resultant regulatory asset would be amortized as a charge monthly to fuel expense, Account 501, on a straight-line basis over the next fuel clause period. Any over-recovery would be deferred as a regulatory liability in Account 254, Other Regulatory Liabilities, with a charge to fuel expense Account 501, Fuel, and refunded to ratepayers through the fuel clause rider over the next fuel clause period. The regulatory liability would be amortized monthly as a credit to fuel expense, Account 501, on a straight-line basis in the next fuel clause period and returned to ratepayers over that same period. There generally would be no deferral of a carrying cost since the recovery period is short, generally only one year or less.

POSSIBLE EARLY PLANT CLOSURE ACCOUNTING

Q. WHY ARE YOU TESTIFYING WITH REGARD TO POSSIBLE EARLY CLOSURE COSTS?

A. Mr. Baker indicates in his testimony that it is possible that one or more of the Companies' generating units may have to close earlier than the retirement date assumed currently for depreciation accrual purposes due to a physical failure, safety concerns or economic reasons. Mr. Baker has asked me to testify regarding how the Companies would propose to account for any resultant early generating unit closure costs and recover the resultant costs.

Q. IF ONE OF THE COMPANIES' GENERATING UNITS IS SHUT DOWN AT AN EARLIER DATE THAN ITS CURRENT DEPRECIATION RETIREMENT DATE, WHAT WOULD BE THE ACCOUNTING IMPLICATIONS ABSENT ANY SPECIAL RATEMAKING/ACCOUNTING?

A. If an early unanticipated shut down of a generating unit occurs, there will be an undepreciated remaining investment in Account 101, Electric Plant In Service, which would have to be expensed, and there may be a considerably smaller unamortized deferred investment tax credit (DITC) balance in Account 255, Accumulated Deferred Investment Tax Credits, which would have to be taken to income. Also there would be additional losses. The resultant net loss would be recognized as an expense since the Companies' generation/supply businesses ceased practicing regulatory accounting due to the discontinuance of SFAS 71 after the passage of Am. Sub. S.B. No. 3 (S.B. 3) in 1999.

Q. WHAT WOULD THE ACCOUNTING BE IF THE COMPANIES' GENERATION/SUPPLY BUSINESSES WERE STILL COST-BASED REGULATED?

A. Were the Companies' generation/supply businesses still cost-based regulated, they would be able to avoid a loss by either charging the remaining investment to the Accumulated Reserve for Depreciation Account, Account 108, or by setting up the remaining net investment and any other closure related losses as a regulatory asset for future recovery. Either approach would require regulator concurrence. Charging undepreciated remaining early retirement investment balances to the Accumulated Reserve for Depreciation would result in the future inclusion of higher depreciation in the cost-of-service resulting in recovery of the undepreciated amount. If a regulatory asset were recorded, its future amortization would also probably increase future cost-of-service resulting in recovery of the regulatory asset. If the Companies' generating/supply businesses were still cost-based regulated, any remaining DITC balance would be returned to ratepayers through inclusion in cost-of-service. In addition to the net undepreciated investment loss (net of remaining DITC) the Companies may experience additional closure losses if they experience an early unit closure. These costs are described later in my testimony. Early generating unit closure losses would typically be included in a regulatory asset for future recovery when the generation business is subject to cost- based regulation.

Q. HAVE THE COMPANIES EXPERIENCED SUCH EARLY CLOSURE LOSSES SINCE THE PASSAGE OF S.B. 3 AND IF SO HOW WERE THE LOSSES TREATED FOR RATEMAKING/ACCOUNTING PURPOSES?

A. Yes. In 2005 CSP was forced to close its Conesville Units 1 and 2 to address safety concerns that would have required a significant investment to resolve. The required investment was not deemed to be cost effective. Since CSP's generation/supply business was no longer able to practice regulatory accounting and since the RSP rates were already fixed, CSP recognized a net loss of $39 million which included a net undepreciated investment and unusable M&S inventory, etc. This unusual significant net accounting loss was not recovered from ratepayers since it was not contemplated and, therefore, was not included in the determination of the already adjudicated RSP rate increases.

Q. ARE THE COMPANIES PROPOSING ANY SPECIAL RATEMAKING/ACCOUNTING TREATMENT TO ADDRESS THE POSSIBLE FUTURE EARLY CLOSINGS OF THEIR GENERATING UNITS IN THIS ESP FILING?

A. Yes. The Companies are requesting that the PUCO authorize them to establish a regulatory asset for ratemaking purposes to defer any such unanticipated net early closure costs that the Companies may experience in Account 182.3, Other Regulatory Assets. If one of the Companies experience net early closure costs and recognizes a regulatory asset for ratemaking purposes under the requested PUCO authorization, it will file a timely request with the PUCO to recover such prudent early closure costs through a non-bypassable rider over a reasonable relatively short period of years. In order to make the Company with the net early closure costs whole, the Companies propose that pending recovery, a carrying cost also be established as a regulatory asset at a WACC rate on the unrecovered balance of the combined regulatory asset until the regulatory deferral is fully recovered. The Companies propose to use a 50/50 debt to equity ratio, actual debt costs and an ROE of 10.5% to compute such carrying cost WACC rate. The 10.5% ROE rate is the last ROE rate the PUCO authorized the Companies to use in computing a carrying cost. Mr. Nelson supports both the 50/50 debt to equity ratio and the 10.5% ROE rate in his testimony. The net early closure regulatory asset would be amortized on a straight-line basis over an approved recovery period.

Q. WHY ARE THE COMPANIES REQUESTING, IF NECESSARY, TO DEFER FOR FUTURE RECOVERY, ON A NON-BYPASSABLE BASIS, EARLY GENERATING UNIT CLOSURE COSTS?

A. An early closure of any of the Companies' generating units would result in net early closure costs that were not previously contemplated or anticipated. The Companies' current RSP rates do not provide for recovery of these unexpected net early closure costs. Had the Companies' generation/supply operations not been required to cease the application of SFAS 71 regulatory accounting as a result of no longer being cost-based regulated due to the passage of S.B. 3, these costs would have been recoverable through the ratemaking process.

Since these generating units have served and will continue to serve the ratepayers, it is reasonable that the Companies should be allowed to recover net early closure costs that would have been recovered had their generation/supply business not been unbundled and taken off of traditional cost-based ratemaking by the enactment of S.B.3 in 1999. It would not be reasonable to expect shareholders to absorb net early closure costs when the unit being shut down early not only benefited ratepayers for its past productive life but will also continue to benefit ratepayers under the provisions of S.B. 221 for the remainder of its productive life. Further, if the Companies were on a full market rate basis for their generation businesses they would not be making this request.

S.B. 221 marks the evolution of the transition off of cost-based rates that began in 1999. Any net early closure costs would be a portion of prudently incurred investments made by the Companies, not yet paid for by ratepayers, which were prudently made to serve the ratepayers during the period when regulatory statutes imposed a requirement to serve customers at a cost-based regulated price. The net early closure costs represent dollars invested in plants built during a regulatory regime in which the Companies were permitted to recover all prudently incurred costs including plant closure costs.

Since the Companies were not permitted to transition to full market rates in 2006 and will not be transitioning in 2009 it seems reasonable that they should be permitted to recover any net early closure costs according to expectations of cost recovery established under that former regulatory regime. The existence of a POLR obligation should continue to cause the ratepayers to have responsibility for any early generating unit closure losses. Under S.B. 3, the Companies were willing to absorb the risk of unexpected costs, such as net early generating unit closure costs, and have done so regarding Conesville Units 1 and 2 under the expectation that they would transition to market-based rates in 2006. Such net early closure costs would have been recovered had the Companies generation/supply businesses not been unbundled and taken off of traditional cost-based ratemaking. Fairness requires that these unusual and potentially significant possible generating plant related losses, if they occur, be recovered from ratepayers, until the transition to market rates is complete.

Q. **WHAT ARE THE ACCOUNTING IMPLICATIONS IF THE RETIREMENT DATE FOR A GENERATING UNIT IS REVISED TO AN EARLIER DATE IN ANTICIPATION OF A FUTURE CLOSING OF A GENERATING UNIT?**

A. When it becomes evident that a depreciable asset is going to be retired in the future at an earlier date than planned for depreciation accrual purposes, the Company would be required by GAAP to accelerate its depreciation over the assets' estimated remaining useful life. In the event such decision is made, the Companies would intend to come back to the Commission to determine the appropriate treatment for such accelerated depreciation and other early closure costs.

Q. **WHAT ARE THE OTHER POSSIBLE NET EARLY CLOSURE COSTS THAT YOU PREVIOUSLY MENTIONED THAT THE COMPANIES MAY HAVE TO RECOGNIZE IN THE FUTURE IF A DECISION IS MADE TO SHUT DOWN A GENERATING UNIT EARLY?**

A. In addition to undepreciated net investment balances when a generating unit shuts down unexpectedly after a failure occurs or a safety concern is identified and total accelerated depreciation when an earlier than originally anticipated shutdown is planned, net early closure costs could include M&S inventory losses and coal pile losses or gains from the existence of coal at the bottom of the coal pile that is not on the Companies' coal pile inventory records.

Q. WHY WOULD THERE BE M&S INVENTORY LOSSES AS A RESULT OF AN EARLY CLOSURE OF A GENERATING UNIT?

A. A portion of the M&S inventory that the owning Company maintains for repairing or replacing equipment on each of the subject generating units is specifically designed for use on those units. Inventory that is specifically designed for a unit being retired early will need to be disposed of generally at a loss net of any salvage value. In addition, after the closing, many non-unit specific M&S items will no longer be needed and would also likely be sold for scrap at a loss.

Q. WHAT CAN CAUSE AN UNRECOVERED COAL LOSS OR GAIN AT THE BOTTOM OF THE COAL PILE AFTER A GENERATING UNIT IS SHUT DOWN?

A. Two main factors over the life of a unit's coal pile can account for such a loss. Coal can and does burn inside the coal pile. This is evidenced by smoke that can be seen rising out of coal piles. Also, the extreme weight of the pile can, over years, force coal at the bottom of the pile into the ground (the gravel coal pile base) making its recovery impractical. Although we try to estimate for such losses, these losses cannot be precisely estimated in periodic coal pile surveys over the life of the coal pile and over a long period can produce significant differences between coal pile inventory records and the actual tonnages on the ground. Although not likely, a gain is also possible.

Q. **HOW WILL COAL INVENTORY REMAINING ON THE BOOKS WHEN ALL OF THE COAL IS BURNED AND SHIPPED TO OTHER COAL PILES OR COAL AT THE BOTTOM OF THE PILE NOT ON THE BOOKS BE PRICED?**

A. These negative and positive coal tonnages will be priced at the then current average coal pile cost per ton, which should equal the remaining cost in the plants 151, Fuel Stock Account for negative tonnages.

Q. **HOW DO THE COMPANIES PROPOSE TO RECOVER THE AMOUNT OF ANY OVER OR UNDER-RECOVERED COAL PILE ADJUSTMENT IN AN EARLY CLOSURE SITUATION?**

A. It would be preferable to treat this type of final coal pile loss as a fuel cost. The Companies propose that the PUCO approve in this proceeding that any such adjustment be deferred as part of the Companies' proposed under/over recovery FAC mechanism to be recovered or returned to customers in the next succeeding FAC proceeding since coal pile adjustments are regularly reflected in the fuel clause and it will expedite recovery. If the amount of such loss is considered to be significant, its recovery could be spread over multiple future FAC periods.

REGULATORY ASSET COST RECOVERY TRACKER ACCOUNTING

Q. PLEASE DISCUSS THE COMPANIES' PROPOSAL TO RECOVER CERTAIN APPROVED REGULATORY ASSETS.

A. The Companies are proposing to amortize and recover PUCO previously authorized regulatory assets not yet being recovered over an 8-year period beginning with the first billing cycle in 2011 through its Regulatory Asset Cost Recovery rider. The Companies will set the recovery rider to recover the estimated amortization of the estimated balances of these regulatory assets at December 31, 2010 and will true-up the rider recovery annually to the actual amortization of the actual regulatory asset balances throughout the 8-year recovery period, from 2011 to 2018. In addition the unrecovered deferred balances will continue to accrue a carrying cost, as authorized, until fully recovered.

Q. PLEASE LIST THE REGULATORY ASSETS THAT THE COMPANIES ARE REQUESTING TO RECOVER AND THE COMMISSION'S PRIOR AUTHORIZATION TO RECORD THESE REGULATORY ASSETS WITH A CARRYING COST.

A. The Companies have deferred the following costs as regulatory assets to be recovered in the future in accordance with the PUCO orders noted below:

- Consumer education, customer choice implementation, and transition plan filing costs plus carrying charges in accordance with the PUCO's transition order in Case Nos. 99-1729-EL-ETP and 99-1730-EL-ETP dated September 28, 2000

- Rate case expenses plus carrying charges in accordance with the PUCO's order in the Companies' Rate Stabilization Plans Filing in Case No. 04-169-EL-UNC dated January 26, 2005
- Carrying charges on distribution line extension charges in accordance with the PUCO's order in Case No. 01-2708-EL-COI dated November 7, 2002
- Monongahela Power Company transfer integration costs plus carrying charges and acquired net regulatory assets in accordance with the order in Case No. 05-765-EL-UNC dated November 9, 2005
- The Companies' voluntary Ohio Green Power Pricing Program costs in accordance with the PUCO's order in Case No. 06-1153-EL-UNC dated March 23, 2007.

Q. PLEASE DISCUSS THE REGULATORY ASSETS FOR CONSUMER EDUCATION, CUSTOMER CHOICE IMPLEMENTATION, AND TRANSITION PLAN FILING COSTS PLUS CARRYING CHARGES THEREON THAT THE COMPANIES ARE REQUESTING TO RECOVER.

A. The regulatory assets for consumer education, customer choice implementation, and transition plan filing costs consist of non-capital software infrastructure costs and depreciation expense on capitalized software infrastructure costs that resulted from the S.B.3. In accordance with the approved settlement agreement in Case Nos. 99-1729-EL-ETP and 99-1730-EL-ETP the first $40 million ($20 million each for CSP and OPCo) of transition costs incurred were expensed; costs in excess of each Company's initial $20 million plus a carrying charge on such deferred excess have been deferred in accordance with the PUCO approved transition settlement agreement. These transition costs have been deferred as regulatory assets since October 2000.

Q. PLEASE DISCUSS THE REGULATORY ASSETS FOR RATE CASE EXPENSES AND CARRYING CHARGES THAT THE COMPANIES ARE REQUESTING TO RECOVER.

A. The regulatory assets for rate case expenses and carrying charges consist of incremental costs such as outside legal expenses and transcript costs and the carrying charges thereon for OPCo and CSP's Rate Stabilization Plan (RSP) filings. These regulatory assets are for costs incurred beginning in March 2004 and carrying charges beginning in January 2005 upon PUCO approval of a carrying cost.

Q. PLEASE DISCUSS THE REGULATORY ASSETS FOR CARRYING CHARGES ON DISTRIBUTION LINE EXTENSION EXPENDITURES THAT THE COMPANIES ARE REQUESTING TO RECOVER.

A. The regulatory assets for carrying charges on distribution line extension expenditures consist of carrying charges on the cost of extending local distribution facilities (i.e., electric facilities constructed for, and dedicated to, the service of an individual end-use customer or the service for a development) to serve new customers or to serve expanded loads of existing customers. These regulatory assets have been deferred since December 2002 for future recovery in accordance with the PUCO's Order in Case No. 01-2708-EL-COI and were scheduled to cease for CSP at the end of 2008 and for OPCo at the end of 2007. However, under a recent order in Case No. 08-65-EL-ATA, dated April 16, 2008 additional deferrals will continue for OPCo through the end of 2008. In this filing, Companies' witness Mr. Earl is proposing to continue the deferral for future recovery of post-2008 line extension carrying costs plus an on-going carrying cost. If approved, these post-2008 line extension carrying costs will be deferred and added to this existing regulatory asset that dates back to 2002. An estimate for these post-2008 costs has been included in an estimate of the balance of this regulatory asset at December 31, 2010 which appears later in this testimony.

Q. PLEASE DISCUSS THE NET REGULATORY ASSETS FOR MONONGAHELA POWER INTEGRATION COSTS PLUS CARRYING CHARGES AND ACQUIRED NET REGULATORY ASSETS THAT CSP IS REQUESTING TO RECOVER.

A. The net regulatory assets for Monongahela Power integration costs plus carrying charges and acquired net regulatory assets consist of the incremental costs incurred associated with integrating Monongahela Power's Ohio distribution assets into CSP's system. The net regulatory assets and liabilities that were transferred to CSP at closing included an Ohio kWh Energy Tax Regulatory Asset, an Ohio Consumer Education Regulatory Asset, an Ohio Deferred Line Extension Carrying Cost Regulatory Asset, a Regulatory Liability for Cost of Removal and deferred tax regulatory assets related to transmission and distribution. These regulatory assets were deferred beginning in November 2005 and additional deferrals will continue for integration costs that continue to be incurred for future recovery under PUCO Order in Case No. 05-765-EL-UNC.

Q. **PLEASE DISCUSS THE REGULATORY ASSETS FOR THE OHIO VOLUNTARY GREEN POWER PRICING PROGRAM THAT THE COMPANIES ARE REQUESTING TO RECOVER.**

A. The regulatory assets for the Ohio Voluntary Green Power Pricing Program consist of the net costs of Renewable Energy Certificates (RECs) purchased and not subscribed or used for meeting the renewable compliance requirement and $125,000 of AEP Ohio's program administration costs. These regulatory assets were deferred for future recovery beginning in July 2007. Additional deferrals will continue under the program through December 31, 2008. The deferrals and their future recovery were provided for in a PUCO Order in Case No. 06-1153-EL-UNC.

Q. **WHAT ARE THE ACTUAL BALANCES AT JUNE 30, 2008 OF THE REGULATORY ASSETS THAT THE COMPANIES ARE REQUESTING TO RECOVER IN THIS ESP FILING?**

A. The actual balances at June 30, 2008 are as follows:

Description	CSP	OPCO
Consumer education, customer choice implementation, and transition plan filing costs plus carrying charges	$34,917,895	$36,140,991
Rate case expenses plus carrying charges	$180,566	$258,153
Carrying charges on distribution line extension charges	$37,539,490	$19,067,764
Mon Power integration costs plus carrying charges and acquired net regulatory assets	$8,552,130	N/A
Ohio Voluntary Green Power Pricing Program	$136,922	$163,319
Total at 6/30/08	$81,327,003	$55,630,227

Q. WHAT ARE THE PROJECTED BALANCES AT DECEMBER 31, 2010 OF THE REGULATORY ASSETS THAT THE COMPANIES ARE REQUESTING TO RECOVER IN THIS ESP FILING?

A. The projected balances at December 31, 2010 of the net regulatory assets the Companies are requesting to recover in this filing are as follows:

Description	CSP	OPCO
Consumer education, customer choice implementation, and transition plan filing costs plus carrying charges	$42,943,464	$45,279,762
Rate case expenses plus carrying charges	$239,132	$354,740
Carrying charges on distribution line extension charges	$63,860,080*	$34,532,789*
Mon Power integration costs plus carrying charges and acquired net regulatory assets	$13,417,589	N/A
Ohio Voluntary Green Power Pricing Program	$0	$88,519
Total Projected at 12/31/10	$120,460,265	$80,255,810

* includes proposed line extension charges post 2008 in accordance with witness Earl's proposal to extend the fully loaded capital line extension carrying cost deferral after the December 31, 2008 termination date in past PUCO orders . Mr. Earl projects annual capital investments of $6.1 million for CSP and $4.7 million for OPCo in 2009 and 2010 with deferred carrying cost of $2.5 million for CSP and $2.0 million for OPCo included above.

Q. WHY ARE THE COMPANIES REQUESTING RECOVERY OF THESE PREVIOUSLY APPROVED REGULATORY ASSETS IN THIS ESP FILING?

A. The intent of the PUCO when it approved the creation of these regulatory assets for future recovery was that they would be recovered in the Companies' next distribution rate filing. Considerable time has passed since the early 2000s when most of these deferral dollars commenced and the Companies have not yet filed a distribution rate case due to agreed to rate freezes that have been in place under the ETP settlement and the Companies' RSPs. Since this ESP filing is proposing to increase distribution rates, it is appropriate that these distribution related regulatory assets be included through a rider so recovery can commence and the increasing balances can start to decline. This will reduce the future amount of accrued carrying costs.

Q. HOW ARE THE COMPANIES PROPOSING TO RECOVER THESE EXISTING REGULATORY ASSETS NOT PRESENTLY BEING RECOVERED?

A. The Companies are proposing to recover the above regulatory assets, including Mr. Earl's proposed extension of the line extension carrying costs recovery post December 31, 2008, through a special Regulatory Asset Cost Recovery rider which will commence with the first billing cycle in 2011 and end eight years later at the end of 2018. The rider revenues will be tracked to actual amortization expense on an annual basis and adjusted for any under/over recovery that may occur.

Q. **WHY ARE THE COMPANIES REQUESTING AN EIGHT-YEAR RECOVERY OF THE REGULATORY ASSETS THAT WILL CONTINUE BEYOND THE ESP PERIOD?**

A. The Companies are requesting recovery over 8 years since that period is similar in length to the length of time that most of these costs were deferred as regulatory assets. In addition, recovery over 8 years will minimize the annual impact on ratepayers.

Q. **HOW DO THE COMPANIES PROPOSE TO ACCOUNT FOR THE AMORTIZATION OF THE REGULATORY ASSETS?**

A. The Companies will credit these regulatory asset accounts in Account 182.3, Other Regulatory Assets, and charge an appropriate expense account with the straight-line amortization over a declining eight-year period beginning in 2011. The function and expense accounts charged would depend on the nature of the items that were originally deferred.

Q. **HOW DO THE COMPANIES PROPOSE TO COMPUTE AND ACCOUNT FOR THE ON-GOING ACCRUAL OF A CARRYING COST?**

A. The Companies will continue through full recovery in 2018 to compute a carrying cost on each of the authorized regulatory asset balances based on a 50/50 capitalization, actual average debt costs and an ROE of 10.5%. Mr. Nelson supports this WACC determination in his testimony. The debt component of the carrying cost will be deferred by debiting Account 182.3, Other Regulatory Assets, and crediting Account 421, Miscellaneous Nonoperating Income. The equity component of the carrying cost will be tracked but it will not be deferred in accordance with SFAS 92, paragraph 9 that indicates that equity should not be recognized as income until collected, except during construction.

Q. HOW DO THE COMPANIES PROPOSE TO ACCOUNT FOR UNDER OR OVER RECOVERY OF THE AMORTIZATION OF REGULATORY ASSETS?

A. The regulatory assets will be amortized on a straight-line basis over eight years. The Companies propose to record a regulatory asset by charging Account 182.3 Other Regulatory Assets, and crediting the appropriate functional expense account for any under recovery as compared to the straight-line amortization adjusted for any on-going deferrals. For over-recoveries, the Companies propose to credit Account 254, Regulatory Liabilities, and charge the appropriate functional expense account. Such under/over recovery deferrals, if any, will adjust the Regulatory Asset Cost Recovery rider annually and will be finally trued up to actual at the end of the eight-year recovery period, 2011 to 2018.

Q. PLEASE PROVIDE AN EXHIBIT THAT DEMONSTRATES FOR EACH COMPANY AN EIGHT-YEAR RECOVERY WITH A CARRYING COST ASSUMING THAT THE AMOUNT TO BE RECOVERED IS THE ABOVE ESTIMATES OF THE REGULATORY ASSET BALANCES AT DECEMBER 31, 2010, THERE ARE NO ADDITIONAL DEFERRALS OR UNDER/OVER RECOVERY TRACKER ADJUSTMENTS SUBSEQUENT

TO 2010 AND THE CARRYING COST IS COMPUTED AT A WACC RATE OF RETURN.

A. Attached as Exhibit LVA-2 is the requested information. It should be noted that the actual amounts would include under/over recovery deferrals to true-up the rider revenues to the actual amortization of the actual regulatory asset balances and additional on-going deferrals which along with actual debt costs will change throughout the recovery period.

Q. **PLEASE SUMMARIZE WHAT THE EXHIBIT SHOWS?**

A. The exhibit indicates that the annual revenue requirement (amortization) for recovery of these regulatory assets over eight years starting in 2011 is $23 million for CSP and $15 million for OPCo and the total revenue requirement (amortization) over the eight-year period with carrying costs is $182 million for CSP and $122 million for OPCo. Again the amortization will change with any additional deferrals, under/over recovery adjustments and changes in actual average debt costs.

gridSMART PROGRAM ACCOUNTING

Q. **PLEASE DESCRIBE THE gridSMART PROGRAM THAT CSP WILL BE INITIATING.**

A. Companies' witness Ms. Sloneker describes the gridSMART Program in her testimony and includes the estimated costs of the program including the cost associated with the premature retirement of existing meters and other equipment to be replaced by so called smart meters and equipment that can communicate with the smart meters. CSP is proposing to recover the O&M and capital costs of the program including the cost of non-reusable meters and other replaced equipment, if any, through an ESP percentage increase on the distribution rate. Briefly as it relates to my accounting testimony, CSP will be installing Advanced Metering equipment or smart meters in Phase 1 of its gridSMART program. Phase 1 in the Northeast Columbus area will commence in the initial ESP period. Presently smart meters have two components: a plug in communications/computer component and a basic meter component. In the near future it is expected that smart meters will be one integrated device. The meters will be owned by CSP. If the program is successful, CSP expects to also be placing, in the not too distant future, with the customer's permission, programmable communicating thermostats (PCT's) and other control devices, such as load control switches (LCSs) in the customer's premises to control the use of certain major appliances and in-home displays (IHDs) to provide customers with real time information regarding energy costs and use. With the possible exception of the PCTs, these in home devices will probably also be owned by CSP. Since the PCT will be attached to the customer's walls and wired to the customer's electrical and heating and cooling systems, the customer may own the PCT device. CSP will also be installing two-way wireless communication systems, and replacement reclosures, switches and voltage regulators with communication capability. Since old reclosures, switches and voltage regulators do not allow for the attachment of communication devices, they will have to be replaced, however, it is expected that they can be reused or salvaged for parts.

The smart meters will be able to communicate with the in-home devices and with the two-way wireless communication systems. It is expected that in the next 5 to 7 years the initially installed smart meters plus some of the communication equipment will be replaced with upgraded technology with greater functionality and benefit to both the customer and CSP.

Q. HOW DOES CSP PROPOSE TO ACCOUNT FOR THE gridSMART PROGRAM EXPENDITURES?

A. The old traditional meters being removed had a longer expected life and were one retirement unit. Although the current smart meters have two separate components, a communication/computer component with an expected seven-year useful life and a basic meter component with a fifteen-year physical life (per the manufacturer) the current smart meters will be capitalized when acquired as one retirement unit with a seven- year life because by the time the meters are replaced in five to seven years with advanced smart meters, the new advanced smart meters are expected to be one integrated meter requiring that the entire meter be replaced and not just the communication/computer component of the original smart meter. As such, we are proposing to continue to have one separate retirement unit for the smart meters with an expected useful life of seven years. CSP is also proposing that the purchase cost of the smart meter plus its installation cost be in Subaccount 370, Meters, of Account 101, Electric Plant In Service, and be depreciated on a composite depreciation method over that same 7 years. Presently meters are in Subaccount 370 and have a 30-year life. In accordance with the FERC Uniform System of Accounts, CSP capitalizes meters in Account 370 upon their acquisition. When installed, the initial installation cost is also capitalized to Account 370. CSP is not proposing to change this FERC approved practice for smart meters.

However, when in-home devices (PCTs, LCSs and IHDs) to be placed in the customers' premises, are purchased, CSP is proposing to record them in Account 154, M&S Inventory and capitalize them in Subaccount 371, Installations on Customers Premises, when installed along with the installation costs if the in-home control devices are to be owned by CSP. The owned control devices will be depreciated on a composite basis over fifteen years, their expected useful life. If the control device is to be owned by the customer, such as may be the case for smart thermostats (PCTs), it will be removed from M&S inventory account and expensed in Account 586, Meter Expenses (which includes devices associated with meters), to be recovered with other non-capital gridSMART program costs through an ESP percentage increase on distribution rates. The cost of the wireless communication equipment will be in Subaccount 397, Communication Equipment, and will have a seven-year life, its expected useful life, since it is expected that they will also have to be replaced in 5 to 7 years to upgrade to the advanced technology. It should be noted that Account 397 presently has a composite life of 15 years.

Central software will be purchased and installed to allow the smart meters to function and provide beneficial information and controls to both CSP and the customers. This software will be depreciated in Subaccount 303, Miscellaneous Intangible Plant, over the traditional five-year life for software.

Finally, certain older distribution equipment such as switches, reclosures, and voltage regulators, will have to be upgraded or replaced to facilitate the addition of communication devices. The cost of the new switches and reclosures will be recorded in Subaccount 365, Conductors, and voltage regulators will be recorded in Subaccount 368, Line Transformers, and depreciated over the existing long lives for these existing accounts. The cost of upgrading the distribution equipment, if a maintenance expense, would be expensed for recovery through the ESP percentage increase in distribution rates. The cost of new switches, reclosures and voltage regulators will be depreciated over the existing thirty-year life for the Conductor account, Account 365 and the existing thirty five-year life for Line Transformer account, Account 368. It is being assumed that the old switches, reclosures and voltage regulators replaced in gridSMART Phase 1 will be reused or used for parts and it is also reasonable to assume that they will be pretty much fully depreciated when replaced. As such the cost of this replaced equipment has not been included in the gridSMART program costs included in Ms. Sloneker's testimony.

Q. WHY IS CSP PROPOSING TO USE A RELATIVELY SHORT LIFE FOR THE SMART METERS WHEN THE MANUFACTURER CLAIMS THEY SHOULD HAVE A PHYSICAL LIFE OF 15 YEARS?

A. GAAP requires that depreciable assets be depreciated over their expected useful life and not their physical lives. To depreciate the smart meter equipment over its physical life or an arbitrary longer life instead of its expected useful life will probably result in a large undepreciated balance when as expected, to upgrade the technology, the smart meters are replaced in mass in 5 to 7 years. Like computers, wireless phones and cell phones, smart metering equipment is state of the art equipment in an area where technology is expected to improve rapidly and as such, like computers and cell phones, the smart meters will have to be replaced before the expiration of their physical life to upgrade to the second or third generation of smart metering technology. This is routinely true for computers and cell phones and our engineers believe it will also be the case for the smart meter which is a computer/communication device.

Q. HOW IS CSP PROPOSING TO ACCOUNT FOR THE PREMATURE RETIREMENT AND REMOVAL OF THE EXISTING TRADITIONAL LONG LIVED METERS, UNDER CSP's gridSMART PROGRAM PHASE 1?

A. If a mass plant asset, such as a meter, is retired and removed from service prematurely in the normal course of business, its remaining book value is traditionally charged to the Account 108, Reserve for Accumulated Depreciation, along with the net removal cost (net of any salvage) for cost-based regulated companies. Charging the reserve for premature retirements in the normal course of business provides for recovery of the undepreciated balance and the net cost of removal over the remaining life of the assets in the mass property account by causing a small increase in the on-going composite depreciation rates in the next Depreciation Study. However, a mass premature retirement of the existing meters to be replaced with smart meters is an extraordinary retirement that cannot be charged to the reserve without distorting the reserve and must be expensed unless it is recoverable through future rates as a regulatory asset. As a result, CSP is proposing that the estimated remaining book value of the existing meters replaced, and retired in mass in the gridSMART program Phase 1 together with the net removal cost (removal cost net of salvage recoveries) be recovered through the ESP percentage increase in distribution rates as a program expense. Ms. Sloneker has included an estimate in her testimony for this mass retirement cost in her estimated total gridSMART program Phase 1 costs to be recovered in this filing.

Q. **HOW DOES CSP PROPOSE TO RECOVER THE DEPRECIATION EXPENSE AND OTHER FIXED COSTS ASSOCIATED WITH THE gridSMART SMART METERING REPLACEMENT EQUIPMENT INCLUDING THE COST TO FINANCE THE INVESTMENT, PROPERTY TAXES, ETC.?**

A. CSP proposes to recover the depreciation expense and other fixed costs associated with the new gridSMART equipment through the ESP percentage increase in distribution rates. Since the estimated cost of the gridSMART program will be included in the current distribution tariffs, it is not necessary for CSP to propose to defer such cost for future recovery. The estimated gridSMART cost recovery revenue requirement will include a capital carrying cost on the undepreciated balances in the gridSMART subaccounts of Accounts 370, 371, 397, 365, 303, 368 and 154 computed at a capital carrying cost rate developed by Mr. Nelson and employed by Ms. Sloneker to develop the annual cost associated with the new gridSMART program equipment. This capital carrying cost rate includes a

WACC rate and other capital related costs like property taxes, other taxes, income taxes etc. A capital rate is appropriate to provide a return of and a return on these capital expenditures. CSP is proposing to use a 50/50 debt to equity ratio, actual debt costs and a ROE of 10.5% to compute the carrying cost WACC rate component of the capital carrying cost rate. Companies witness Mr. Roush employed a capital carrying cost rate provided to him by Mr. Nelson to apply to the net gridSMART plant balances estimated by Ms. Sloneker to arrive at the capital cost component of the revenue requirement to be recovered together with all other gridSMART program costs through the ESP percentage increase in distribution rates. Mr. Nelson also supports the use of a 50/50 capital structure and a 10.5% ROE rate and the other components of his capital carrying cost rate.

E.E. AND D.R. (DSM) PROGRAMS TRACKER ACCOUNTING

Q. ARE THERE ANY OTHER ITEMS THAT YOU WOULD LIKE TO ADDRESS IN YOUR DIRECT TESTIMONY?

A. Yes, I will address the accounting for incurred Energy Efficiency and Peak Demand Reduction (DSM) program costs and the annual tracker discussed in Ms. Sloneker's and Mr. Roush's testimony proposed by the Companies in this ESP filing.

Q. WHAT ACCOUNTING DO THE COMPANIES INTEND TO EMPLOY TO ACCOUNT FOR INCURRED DSM PROGRAM COSTS?

A. The Companies intend to expense all incurred DSM program expenses in Account 908, Customer Assistance Expense. The estimated annual DSM program costs will be recovered through an Energy Efficiency and Peak Demand Reduction Cost Recovery rider. The recoveries under the rider will be trued-up annually to actual DSM costs. The rider recovery will be compared to the amortization of the actual deferral on an annual basis and trued-up to actual through an annual tracker mechanism.

Q. HOW DO THE COMPANIES INTEND TO ACCOUNT FOR THE ANNUAL TRUE-UP PROPOSED IN THIS PROCEEDING?

A. During the three-year period the Energy Efficiency and Peak Demand Reduction Cost Recovery (DSM) tracker will be in effect, the Companies intend to defer any under-recovery monthly, as a regulatory asset in Account 182.3, Other Regulatory Assets, and, any over-recovery will be recorded as a regulatory liability in Account 254, Other Regulatory Liabilities, for future recovery or refund through an annual true-up to actual. The tracker net regulatory asset or liability at December 31, 2009 will be amortized over twelve months ended December 31, 2010 to produce expense or income commensurate with its recovery or refund through DSM tracker revenues in that same twelve-month period. The process will be reported annually for as long as the DSM programs are in place. See Mr. Roush's testimony for a discussion of the tracker mechanism.

<u>ECONOMIC DEVELOPMENT TRACKER</u>

Q. ARE YOU PROPOSING TO DO ANY SPECIAL ACCOUNTING FOR THE ECONOMIC DEVELOPMENT TRACKER?

A. No. The economic development discounts provided to non-residential customers and other economic development costs will be tracked by AEP Ohio. Mr. Roush will adjust the Economic Development rider quarterly to recover the lost revenues from the discounts and other economic development costs reported to him by AEP Ohio. Mr. Roush will also adjust the rider annually for any over or under recoveries. Recovery will be over twelve months. This is a relatively simple and short process and as a result the Companies are not recommending any special under/over regulatory asset/regulatory liability accounting. AEP Ohio will maintain an electronic record of the discounts and program costs.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Columbus Southern Power Company
Ohio Power Company
Illustration of Proposed Phase In of Incremental 2009 FAC Costs
(See Major Assumptions Below)
($ in millions)

	Year										
	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	Total
Columbus Southern Power Company											
Base FAC Revenue Requirement	260.0	260.0	260.0								780.0
Base FAC Revenues Collected	148.0	260.0	260.0	30.2	30.2	30.2	30.2	30.2	30.2	30.2	879.4
Deferred FAC Expense (Credit)	(112.0)	0.0	0.0	11.2	12.5	14.0	15.6	17.5	19.5	21.7	0.0
Deferred Carrying Charge	(6.2)	(13.2)	(14.7)	(15.7)	(14.0)	(12.1)	(10.0)	(7.6)	(5.0)	(0.9)	(99.4)
Amortization of Deferred Carrying Charge				19.0	17.7	16.2	14.6	12.7	10.7	8.5	99.4
Regulatory Asset Balance	118.2	131.4	146.1	131.6	115.4	97.3	77.1	54.5	29.3	0.0	
Ohio Power Company											
Base FAC Revenue Requirement	367.0	367.0	367.0								1,101.0
Base FAC Revenues Collected	67.0	228.0	367.0	114.4	114.4	114.4	114.4	114.4	114.4	114.4	1,462.8
Deferred FAC Expense (Credit)	(300.0)	(139.0)	0.0	43.9	49.0	54.8	61.2	68.4	76.4	85.3	0.0
Deferred Carrying Charge	(16.7)	(43.1)	(55.6)	(59.4)	(53.0)	(45.8)	(37.8)	(28.8)	(18.8)	(2.8)	(361.8)
Amortization of Deferred Carrying Charge				70.5	65.4	59.6	53.2	46.0	38.0	29.1	361.8
Regulatory Asset Balance	316.7	498.8	554.4	499.4	438.0	369.4	292.8	207.2	111.6	(0.0)	

Major Assumptions:
Based on estimated 2009 incremental FAC costs of $260 million for CSP and $367 million for OPCo and an estimate of the percentage of Base FAC revenues collected in 2009, 2010 and 2011 per page 13 of the application. Assumes incremental FAC costs do not change from 2009 to 2010 and from 2010 to 2011. Also assumes a before-tax weighted average carrying cost rate of 11.15%

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Columbus Southern Power Company
Ohio Power Company
Illustration of Proposed Recovery of PUCO Previously Authorized Regulatory Assets
(See Major Assumptions Below)
($ in millions)

	Year									
	2010	2011	2012	2013	2014	2015	2016	2017	2018	Total
Columbus Southern Power Company										
Regulatory Asset Revenue Requirement		22.8	22.8	22.8	22.8	22.8	22.8	22.8	22.8	182.4
Amortization of Regulatory Asset		15.1	15.1	15.1	15.1	15.1	15.1	15.1	14.8	120.5
Deferred Carrying Charge		(12.7)	(11.6)	(10.3)	(8.9)	(7.4)	(5.7)	(3.7)	(1.6)	(61.9)
Amortization of Deferred Carrying Charge		7.7	7.7	7.7	7.7	7.7	7.7	7.7	8.0	61.9
Regulatory Asset Balance	120.5	110.4	99.2	86.7	72.8	57.4	40.3	21.2	0.0	
Ohio Power Company										
Regulatory Asset Revenue Requirement		15.2	15.2	15.2	15.2	15.2	15.2	15.2	15.2	121.6
Amortization of Regulatory Asset		10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.3	80.3
Deferred Carrying Charge		(8.5)	(7.7)	(6.9)	(6.0)	(5.0)	(3.7)	(2.4)	(1.1)	(41.3)
Amortization of Deferred Carrying Charge		5.2	5.2	5.2	5.2	5.2	5.2	5.2	4.9	41.3
Regulatory Asset Balance	80.3	73.6	66.1	57.8	48.6	38.4	26.9	14.1	0.0	

Major Assumptions:
Based on estimated total regulatory assets at December 31, 2010 of $120.5 million for CSP and $80.3 million for OPCo. Assumes no additional deferrals in 2011 to 2018 due to estimates being unavailable beyond 2010. Also assumes a before-tax weighted average carrying cost rate of 11.15%