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January 29, 1993

Ronald E. Hawkins
Executive Secretary
Public Service Commission
of Maryland
American Building, 15th Floor
231 East Baltimore Street
Baltimore, Maryland 21202-3486

Re: Case No. 8179

Dear Mr. Hawkins:

Enclosed please find an original and fourteen (14) copies of the Direct Testimony and Exhibits of Paul L. Chernick on behalf of Maryland Office of People's Counsel in the above-referenced case.

Copies have been sent to all parties of record.

Very truly yours,

Paul S. Buckley

Paul S. Buckley
Deputy People's Counsel

IRP
4 - Westvaco - 1
6 - Staff - 1

PSB/mcm
Enclosure
cc: All Parties of Record
Mr. Paul L. Chernick

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STATE OF MARYLAND
PUBLIC SERVICE COMMISSION

In the Matter of the Petition of Potomac Edison for Approval of Amendment No. 2 to the Electric Energy Purchase Agreement with AES Warrior Run, Inc.	Case No. 8179

DIRECT TESTIMONY OF

PAUL CHERNICK

ON BEHALF OF THE

MARYLAND OFFICE OF PEOPLE'S COUNSEL

January 29, 1993

RESOURCE INSIGHT, Inc.
18 Tremont Street
Boston MA 02108
(617)-723-1774

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I. IDENTIFICATION AND QUALIFICATIONS

Q: State your name, occupation and business address.

A: I am Paul L. Chernick. I am President of Resource Insight, Inc., 18 Tremont Street, Suite 1000, Boston, Massachusetts.

Q: Summarize your professional education and experience.

A: I received an S.B. degree from the Massachusetts Institute of Technology in June, 1974 from the Civil Engineering Department, and an S.M. degree from the Massachusetts Institute of Technology in February, 1978 in Technology and Policy. I have been elected to membership in the civil engineering honorary society Chi Epsilon, and the engineering honor society Tau Beta Pi, and to associate membership in the research honorary society Sigma Xi.

I was a Utility Analyst for the Massachusetts Attorney General for over three years, and was involved in numerous aspects of utility rate design, costing, load forecasting, and the evaluation of power supply options. Since 1981, I have been a consultant in utility regulation and planning, first as a Research Associate at Analysis and Inference, after 1986 as President of PLC, Inc., and in my current position at Resource Insight, I have advised a variety of clients on utility matters. My work has considered, among other things, the cost-effectiveness of prospective new generation plants and transmission lines; retrospective review of generation planning decisions; ratemaking for plant under construction; ratemaking for excess and/or uneconomical plant entering service; conservation program design; cost recovery for utility efficiency programs; and the valuation of environmental externalities from energy production and use. My resume is Attachment 1 to this testimony.

Q: Have you testified previously in utility proceedings?

A: Yes. I have testified on numerous occasions on utility issues before various regulatory, legislative, and judicial bodies, including the Massachusetts Department of Public Utilities, the Massachusetts Energy Facilities Siting Council, the Vermont Public Service Board, the Texas Public Utilities Commission, the New Mexico Public Service Commission, the District of Columbia Public Service Commission, the New Hampshire Public Utilities Commission, the Connecticut Department of Public Utility Control, the Michigan Public Service Commission, the Maine Public Utilities Commission, the Minnesota Public Utilities Commission, the South Carolina Public Service Commission, the Federal Energy Regulatory Commission, and the Atomic Safety and Licensing Board of the U.S. Nuclear Regulatory Commission. A detailed list of my previous testimony is contained in my resume.

Q: Have you testified previously before this Commission?

A: Yes. I testified in Case No. 8278 and Case No. 8241 on the least-cost planning efforts of Baltimore Gas and Electric Company (BG&E), in Case No. 8473 on the reasonableness of the proposed contract between BG&E and the AES Northside generation project, and in Case No. 8487 on BG&E's cost allocations, marginal costs, and rate design.

Q: **Have you been involved in least-cost utility resource planning?**

A: Yes. I have been involved in utility planning issues since 1978, including load forecasting, the economic evaluation of proposed and existing power plants, and the establishment of rate for qualifying facilities. Most recently, I have been a consultant to various energy conservation design collaboratives in New England, New York, and Maryland; to the Conservation Law Foundation's (CLF's) conservation design project in Jamaica; to CLF interventions in a number of New England rulemaking and adjudicatory proceedings; to the Boston Gas Company on avoided costs and conservation program design; to the City of Chicago in reviewing the Least Cost Plan of Commonwealth Edison; to the South Carolina Consumer Advocate on least-cost planning; to environmental groups in North Carolina, Florida, Ohio and Michigan on DSM planning; and to several parties on incorporating externalities in utility planning and resource acquisition. I also assisted the DC PSC in drafting order 8974 in Formal Case 834 Phase II, which established least-cost planning requirements for the electric and gas utilities serving the District.

I have testified in several proceedings on proposed power purchases, on behalf of qualifying facilities (QFs), consumer advocates, and environmental advocates. In various proceedings, I have advocated the establishment of long-term contracts for power purchases from QFs, higher purchase prices, lower backup charges to QFs, approval of some contracts, and disapproval of other contracts.

Q: Have you testified previously on supply planning and power purchase issues?

A: Yes. I have testified a number of times on cost allocations and rate design, in addition to several related pieces of testimony on such related topics as the allocation of DSM program costs, and the derivation of marginal/avoided costs for evaluation of DSM, non-utility generation and utility supply options.

Q: Are you the author of any publications on utility planning?

A: Yes. I am the author of a number of publications on rate design, cost allocation, power plant cost recovery, conservation program design and cost-benefit analysis, and other utility planning issues. These publications are listed in my resume.

Q: Are you engaged in any least-cost planning activities in Maryland?

A: Yes. I am a consultant for the Maryland Office of People's Counsel (OPC) to the DSM collaboratives for BG&E, WGL and BG&E, as well as more limited roles in collaboratives with Delmarva Power and Potomac Edison. These collaboratives also include the Commission Staff, DNR, and various combinations of other parties. I am generally responsible for issues concerning avoided costs, resource allocation, cost recovery and regulatory policy.

Q: On whose behalf are you testifying?

A: My testimony is being sponsored by the Maryland Office of People's Counsel (OPC).

II. INTRODUCTION

Q: Please describe the purpose of your testimony.

A: The purpose of my testimony is to consider whether the contract between Potomac Edison (PE), a subsidiary of the Allegheny Power System,[1] and AES Warrior Run (AES/WR), a subsidiary of the AES Corporation, amended as proposed in Exhibit RFB-14 to the testimony of Regis F. Binder, is in the interests of PE's ratepayers.

Warrior Run is the proposed successor to AES's Cumberland plant, which was in turn the successor to AES's Petrolia plant, originally planned for construction in Pennsylvania. The Petrolia contract was filed with the Commission in July 1988. The contract, amended for the Cumberland site and with revised pricing terms, was approved by the Commission in February 1989. I will refer to the contract, including Amendment 1, as the "original" contract.

The proposed amendment allows AES to move the plant from the Cumberland site to the Mexico Farms site, and delays the in-service date and certain milestones.

Q: Do you find that the contract, with the proposed amendment, is in the interests of PE's ratepayers?

A: No. The contract for power from the Warrior Run (AES/WR) project will increase costs in the short term, and will lead to higher customer rates and bills in the long term as well.

[1]In this testimony, I do not distinguish between Potomac Edison and Allegheny Power; technically, some of my references to "PE" should be to Allegheny.

Neither the Company nor AES has conducted a rigorous analysis of the contract's costs and benefits. I have compared the cost of the contract to various estimates of PE's avoided costs, and have found that the contract appears not to be cost-effective, and by a wide margin. I recommend that the Commission reject the contract amendment and allow the termination of the project.

Q: **How is the remainder of your testimony organized?**

A: Section III discusses my efforts to determine the cost-effectiveness of the AES/WR contract. Section IV briefly discusses the economic effects of AES/WR on Allegheny County. Section V presents my recommendations to the Commission.

III. THE COST-EFFECTIVENESS OF THE WARRIOR RUN CONTRACT

A. Potomac Edison Has Not Analyzed the New Contract

Q: Has PE analyzed the costs and benefits of the new contract?

A: No. The Company has only provided a comparison of the economics of the original contract to the amended contract. (Binder pp. 9-10, Exh. RFB-15). Assuming that the original contract is unlikely to be fulfilled, this analysis is not very relevant. PE has not considered whether ratepayers would be better off with the amended contract than with no AES contract at all. Instead, PE appears to assume that the original contract is viable, and that it is stuck with the AES/WR purchase, whether cost-effective or not (Binder, p. 13).

Q: Have conditions changed significantly since the original contract?

A: Circumstances have changed dramatically since 1988, when PE expected AES/Cumberland to back out new coal capacity planned for the late 1990s. PE now expects to meet its supply requirements through 2004 with existing plants and new combustion turbines (CTs). Starting in 2005, PE expects to add some oil-fired combined cycle plants (CCs).[2] PE is also involved in a DSM collaborative; over the next decade, a substantial share of PE's incremental resource requirements are likely to met with DSM.

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[2]This information is from PE's 1992 Integrated Resource Plan, or IRP.

In the current circumstance, AES/WR would produce very small variable-cost savings when dispatched against PE's predominately coal-fired system. Hence, AES/WR must pay for itself by backing out new capacity. In 1988, that was an easier task, since AES/Cumberland was backing out expensive new coal-fired capacity. Now, AES/WR would be backing out relatively inexpensive CTs for the first several years of operation, and then slightly more expensive CCs.[3] Neither of these plant types is nearly as expensive as coal plants.

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[3]PE also expects to return to service four older steam units, but AES/WR would enter service too late to affect their timing.

B. Comparison of the Costs of the Amended Contract to the Avoided Costs PE Estimates for QFs

Q: **How does the amended contract compare to PE's avoided-cost estimates?**

A: PE estimates only avoided demand-related capacity costs. As discussed above, the avoided energy costs due to the AES/WR contract will be close to the AES/WR energy charges for many years, until higher-cost fuels become a significant part of PE's mix or an expensive baseload plant is avoidable. Hence, AES/WR is unlikely to be cost-effective if its capacity charge is much higher than the avoided capacity costs.

PE presents a range of avoided capacity costs. I believe that the avoided capacity cost should be based on the cost of the first three CTs. I do not accept PE's argument that CTs planned for 1996-98 are not avoidable in 1993. PE's highest estimate is based on the costs of these units, as they would be timed with 200 MW lower QF purchases than assumed in the 1992 IRP (e.g., without the 180 MW AES/WR purchase). While DSM is likely to delay the need for these additions, using the IRP-200 case is conservatively biased in favor of AES/WR.

PE's estimate of levelized avoided capacity costs, under these most favorable circumstances, is $7.39/kW-month, or about 1.4¢/kWh at a 75% capacity factor (Exh. RFB-23). The levelized capacity charge for AES/WR is 5.7¢/kWh (Exh. C in Exh. RFB-14). This comparison appear to be highly unfavorable to AES/WR.

C. Comparison of the Costs of the Amended Contract to the Avoided Costs PE Uses in Evaluating DSM

Q: **Have you compared the costs of the amended contract to PE's avoided costs?**

A: Yes. Attachment 2 of my testimony contains this comparison. Column [1] shows the annual cost of the contract to PE. These figures were taken from an analysis prepared by AES, provided in IR 1-Westvaco-1.[4] Columns [2] and [3] show PE's levelized avoided energy and generation capacity costs, for a 30-year period beginning in 1997. The avoided costs are taken from the Company's 1992 IRP. Columns [4] and [5] apply these avoided costs to the Warrior Run contract, assuming 180 MW capacity and 1,110,830 MWH/year, as derived from p. 476 of the IRP. Column [6] sums the avoided capacity and energy costs.

Q: **Is it appropriate to compare AES/WR to the avoided costs PE developed for DSM?**

A: Yes, for three reasons. First, both AES/WR and DSM would back out similar energy and generation capacity costs. It is possible that the DSM avoided costs include costs AES/WR would not avoid, such as line losses and the higher energy costs associated with realistic DSM load shapes. If so, the value of AES/WR would be even smaller.[5] Thus, my analysis of AES/WR

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[4]I generally refer to responses to discovery as "IR n-xx-m," where *xx* is the requesting party, *n* is the number of the request, and *m* is the number of the question. The respondent (AES/WR or PE) is clear from context.

[5]I have not been able to determine whether PE's avoided-cost estimates properly include the benefits of additional off-system sales. Hence, PE's avoided costs may be somewhat understated for

may provide too favorable an estimate of the plant's cost-effectiveness.

Second, AES/WR is likely to displace a significant amount of DSM. AES/WR (like any other committed resource) has reduced PE's projections of avoided costs, reducing the amount of cost-effective DSM. Hence, the avoided cost used in screening DSM provides an estimate of the cost of DSM that AES/WR may back out.

Third, while the avoided costs from the IRP are reduced by the assumption that AES/WR will be built, they are overstated by PE's understatement of DSM potential. The avoided costs with an aggressive DSM program but without AES/WR are likely to be similar to, or lower than, comparably estimated avoided costs under the IRP assumptions: with AES/WR but without aggressive DSM.

Q: What does your comparison show?

A: At the bottom of Attachment 2, I calculate the present value of the Warrior Run contract and the present value of avoided costs. I find that in present value terms, the Contract will cost ratepayers an additional $423,400,000, over 30.25 years.

Attachment 3 approximates the annual difference between the cost of the contract and avoided costs. That Attachment shows quite a large difference even in the first full year of operation, at about $54,000,000.

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both DSM and AES/WR.

Q: How did you calculate the avoided cost streams in Attachment 3?

A: The avoided capacity and energy costs in columns [2] and [3] approximate PE's annual avoided costs. The streams are derived from PE's levelized avoided costs, for actions with a lifetime of 10, 15, 20 and 30 years. The annual costs in Attachment 3 were calculated to have the same present value at the streams in Attachment 2.

The levelization of costs over the first 10 years overstates the estimate of the avoided costs and understates the excess of AES/WR costs in the early years.

D. Correcting AES' Analysis of the Amended Contract

Q: Has AES analyzed the costs and benefits of the new contract?

A: Yes. In response to IR 1-Westvaco-1, AES provided a comparison of the AES/WR contract price to AES's estimate of PE's avoided costs. The analysis assumes that AES/WR backs out 180 MW of CTs in 1997-1999, and 180 MW of oil-fired CCs thereafter. In 1997-1999, AES/WR is assumed to replace CT oil at a 5% capacity factor, and existing coal at an additional 65.4% capacity factor. From 2000 on, AES/WR is assumed to back out CC oil at a 70.4% capacity factor.

Q: What errors have you found in AES's analysis?

A: The analysis contains a number of errors.

- AES assumes that the CT's fixed costs are eliminated for the entire analysis period. Given AES's assumption that AES/WR will back out a more expensive CC starting in 2000, the CT's fixed costs are simply deferred, not avoided. The CT would be built in 2000, and would be more expensive throughout the remainder of the analysis period than the earlier CT would have.

Still true

- AES uses CC O&M costs that are much higher than those in the IRP.
- AES vastly overstates the CC capacity factor. The CC is unlikely to operate at anything close to 70% capacity factor; AES/WR would not back out CC oil in most hours, since the CC would not be running. Most AES/WR energy would back down other coal plants.

- AES assumes that a CC would be added in 2000. The IRP projects the addition of a CC in 2004 (IRP Exh. IV.B.4.b-8). Since the CTs are projected to operate at very low capacity factors (about 5%), it is unlikely that earlier CC additions would be cost-effective.

Q: Have you corrected these errors?

A: All but the last item. My corrected version of the AES analysis is shown in Attachment 4. I have added the costs of the deferred CT, which reduces the benefits of AES/WR by about $37 million (1993PV); reduced the CC O&M costs to the levels in the IRP, which reduces the benefits of AES/WR by about $45 million;[6] and assumed that the CC operates at a 15% capacity factor, which reduces the benefits of AES/WR by over $370 million.[7] I have continued AES's category of avoided intermediate fuel costs beyond 2000, to capture the costs of the existing coal backed out by AES/WR. With these corrections, the net cost of the amended AES/WR contract is about $340 million.

Delaying the in-service date of the avoided CC to 2004 would reduce the benefits of AES/WR by another $30 million or so.

Q: What is the basis for your assumption that the avoided CC

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[6]I used the summer capacity of the CC to compute the O&M cost per kW, which overstates the costs for 180 MW of winter capacity.

[7]I also corrected some minor errors in the AES analysis, some of which understated avoided costs, and removed the confusing distinctions between APS, PE, and PE's Maryland jurisdiction in the AES analysis.

would operate at a 15% capacity factor.

A: This estimate is based on review of

- The capacity factors implied by the CC generation levels shown in IRP Exhibit IV.B.4.b. Those capacity factors range from the single digits up to about 22%.
- The PE screening curves in IR 4-Westvaco-1, which imply that even in 1992, CCs would be more expensive than pumped storage above a 15% capacity factor, and more expensive than coal plants above a 33% capacity factor.[8] As the price of #2 oil escalates, the breakeven capacity factors will decrease.
- The very low (2-10%) capacity factors PE projects in IR 6-Staff-1 for the reactivated Mitchell 1&2 and Springdale 7&8 units, which burn #6 fuel oil. PE projects that #2 oil will cost about 52% more than #6 oil by 2001 (IRP pp. 438-441), which more than makes up for the CC's better heat rate.

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[8] Wind generation and compressed air energy storage (CAES) also appear to beat combined cycles at low capacity factors.

IV. EFFECT OF AES/WR ON THE ECONOMY OF WESTERN MARYLAND

Q: What implications do your estimates of the net cost of AES/WR have for the testimony of Dr. Dalton?

A: Dr. Dalton estimates certain benefits to the local economy due to the construction and operation of AES/WR. Given the time limits in this proceeding, I have not reviewed Dr. Dalton's estimates in detail. However, she appears to present the simple sum of nominal benefits, without discounting. Her argument against discounting (Exh. MMD-1, p. 3) appears to imply that her numbers cannot be used for project comparison or evaluation purposes. I agree.

Dr. Dalton also appears to treat all wages as benefits, without counting the costs of lost alternative labor or leisure time.[9] Dr. Dalton apparently includes as a local benefit the cost of coal purchases, without determining the destination of the profits and royalties; and double-counts the costs of wages paid to coal miners, including them both directly and as part of the cost of coal.

However, Dr. Dalton does not appear to reflect the most important effect of the plant on the region, its effect on rates. Since AES/WR would not be cost-effective, it would increase utility bills in PE's service territory, impede economic development, and depress the local economy. Current

[9] Wages are generally assumed to be costs, not benefits, of energy resource projects. Dr. Dalton's approach would count all local expenditures as benefits, even if the expenditures are to dig holes and fill them in.

residents and businesses will have less disposable income, and will hence buy less from other residents and businesses. Existing businesses will be less competitive. Potential new businesses will face higher costs. These cost increases will come on top of increases required to comply with the Clean Air Act Amendments and those driven by general inflation.

As discussed before, AES/WR would also tend to discourage PE from aggressively pursuing DSM programs. Those programs benefit the local economy in two ways. First, they reduce bills, increasing disposable income and the competitiveness of local employers. Second, they train and employ local workers for program administration and measure delivery. Dr. Dalton does not reflect the lost DSM benefits to Allegheny County.

Overall, Dr. Dalton's analysis does not seem to add much of value to the Commission's deliberations. AES/WR is unlikely to be beneficial to PE's service territory or to the state of Maryland.

V. RECOMMENDATIONS TO THE COMMISSION IN THIS CASE.

Q: What recommendations do you have regarding commission approval of the Amendment to the contract between AES and PE?

A: I recommend that the Commission reject the amendment given its poor economics.

Q: Would such rejection be fair to AES, given that a contract for the predecessor project was approved by the Commission?

A: Yes. Had the Cumberland project failed, and avoided costs had risen, AES would have been free to propose the AES/WR project as a new project eligible for higher avoided costs. The Commission is under no obligation to approve the amendment of contracts to allow QFs to retain excessive higher-than-market rates, since the QFs are not obligated to amend contracts to give PE's customer's the benefits of lower-than-market rates negotiated for different sites and schedules.

Q: Would your recommendation change if the Cumberland project were still viable under the original schedule?

A: Yes. Since neither the original contract nor the amended contract is cost-effective, and since AES is unlikely to be able to structure a cost-effective sale from a coal plant to PE in the foreseeable future, the best outcome is the cancellation of both the AES/Cumberland and the AES/WR plants.[10] If AES is actually able to build the plant, and is

[10]Perhaps PE and AES could negotiate an agreement to defer the plant until it would be cost-effective, an event that appears unlikely to occur until after the end of PE's current planning period. PE might pay annual fees to compensate AES for keeping the project licensed and ready to restart, just as PE would do for a

legally entitled to sell power at uneconomic rates to PE, then PE should seek to limit its liability by buying out the contract. This practice has become quite common in other states, for exactly these reasons.

The cost of the buyout to PE will depend on the amount of profit AES expects to earn on the contract. Since AES has indicated that financing will be more expensive under the original schedule than the revised schedule, AES's profit will be lower if the amendment is rejected. Other costs are also likely to be higher, and the lack of slack in the schedule increases AES's risks. Hence, AES should settle for a smaller buyout under the original contract than the amended contract. Approval of the amendment would simply increase AES's bargaining power with PE.

Q: **Does this conclude your testimony?**

A: Yes.

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deferred plant of its own.

Attachment 1

Resume of

Paul L. Chernick

PAUL L. CHERNICK

Resource Insight, Inc.
18 Tremont Street, Suite 1000
Boston, Massachusetts 02108

PROFESSIONAL EXPERIENCE

President, Resource Insight, Inc.
August 1986 - present

Consulting and testimony in utility and insurance economics. Reviewing utility supply planning processes and outcomes: assessing prudence of prior power planning investment decisions, identifying excess generating capacity, analyzing effects of power pool pricing rules on equity and utility incentives. Reviewing electric utility rate design. Estimating magnitude and cost of future load growth. Designing and evaluating electric, natural gas, and water utility conservation programs, including hook-up charges and conservation cost recovery mechanisms.

Determining avoided costs due to cogenerators. Evaluating cogeneration rate risk. Negotiating cogeneration contracts. Reviewing management and pricing of district heating system.

Determining fair profit margins for automobile and workers' compensation insurance lines, incorporating reward for risk, return on investments, and tax effects. Determining profitability of transportation services.

Advising regulatory commissions in least-cost planning, rate design, and cost allocation.

Research Associate, Analysis and Inference, Inc.
May 1981 - August 1986 (Consultant, 1980-1981)

Research, consulting and testimony in various aspects of utility and insurance regulation. Designed self-insurance pool for nuclear decommissioning; estimated probability and cost of insurable events, and rate levels; assessed alternative rate designs. Projected nuclear power plant construction, operation, and decommissioning costs. Assessed reasonableness of earlier estimates of nuclear power plant construction schedules and costs. Reviewed prudence of utility construction decisions.

Consulted on utility rate design issues including small power producer rates; retail natural gas rates; public agency electric rates, and comprehensive electric rate design for a regional power agency. Developed electricity cost allocations between customer classes.

Reviewed district heating system efficiency. Proposed power plant performance standards. Analyzed auto insurance profit requirements.

Designed utility-financed, decentralized conservation program. Analyzed cost-effectiveness of transmission lines.

Utility Rate Analyst, Massachusetts Attorney General
December 1977 - May 1981

Analyzed utility filings and prepared alternative proposals. Participated in rate negotiations, discovery, cross-examination and briefing. Provided extensive expert testimony before various regulatory agencies.

Topics included: demand forecasting, rate design, marginal costs, time-of-use rates, reliability issues, power pool operations, nuclear power cost projections, power plant cost-benefit analysis, energy conservation and alternative energy development.

PROFESSIONAL AFFILIATIONS

Senior Associate, Cambridge Energy Research Associates, Cambridge, Massachusetts.
Associate, Rocky Mountain Institute Competitek Service, Old Snowmass, Colorado.
Member, International Association for Energy Economics, and past Vice-President, New England Chapter.
Member, Association of Energy Engineers, Lilburn, Georgia.

EDUCATION

S.M., Technology and Policy Program, Massachusetts Institute of Technology, February, 1978.

S.B., Civil Engineering Department, Massachusetts Institute of Technology, June, 1974.

HONORARY SOCIETIES

Chi Epsilon (Civil Engineering)
Tau Beta Pi (Engineering)
Sigma Xi (Research)

OTHER HONORS

Institute Award, Institute of Public Utilities, 1981.

PUBLICATIONS

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Chernick, P., Fairley, W., Meyer, M., and Scharff, L., Design, Costs and Acceptability of an Electric Utility Self-Insurance Pool for Assuring the Adequacy of Funds for Nuclear Power Plant Decommissioning Expense, (NUREG/CR-2370), U.S. Nuclear Regulatory Commission, December, 1981.

Chernick, P., Optimal Pricing for Peak Loads and Joint Production: Theory and Applications to Diverse Conditions (Report 77-1), Technology and Policy Program, Massachusetts Institute of Technology, September, 1977.

PRESENTATIONS

American Planning Association 1992 National Planning Conference; May 10, 1992; "Using the Costs of Required Controls to Incorporate the Costs of Environmental Externalities in Non-Environmental Decision-Making."

DSM Advocacy Workshop; April 15, 1992; Session Leader for "Cost Recovery and Decoupling" and "The Clean Air Act and Externalities in Utility Resource Planning" panels.

Energy Planning Workshops; Columbia, S.C.; October 21, 1991; "Overview of Integrated Resources Planning Procedures in South Carolina and Critique of South Carolina Demand Side Management Programs."

Demand-Side Management and the Global Environment Conference; Washington, D.C., April 22, 1991; "Monetizing Environmental Externalities for Inclusion in Demand-Side Management Programs."

Conservation Law Foundation Utility Energy Efficiency Advocacy Workshop; Boston, February 28, 1991; "Least Cost Planning and Gas Utilities."

NARUC Forum on Gas Integrated Resource Planning; Washington, D.C., February 24, 1991; "Least-Cost Planning in a Multi-Fuel Context."

Understanding Massachusetts' New Integrated Resource Management Rules; Needham, Massachusetts, November 9, 1990; "Accounting for Externalities: Why, Which and How?"

National Association of Regulatory Utility Commissioners' National Conference on Environmental Externalities; Jackson Hole, Wyoming, October 1, 1990; "Monetizing Externalities in Utility Regulations: The Role of Control Costs."

New England Gas Association Gas Utility Managers' Conference; Woodstock, Vermont, September 10, 1990; "Increasing Market Share Through Energy Efficiency."

Lawrence Berkeley Laboratory Training Program for Regulatory Staff; Berkeley, California, February 2, 1990; "Quantifying and Valuing Environmental Externalities."

District of Columbia Natural Gas Seminar; Washington, D.C., May 23, 1989; "Conservation in the Future of Natural Gas Local Distribution Companies."

Massachusetts Natural Gas Council; Newton, Massachusetts, April 3, 1989; "Conservation and Load Management for Natural Gas Utilities."

New England Conference of Public Utilities Commissioners, Environmental Externalities Workshop; Portsmouth, N.H., January 22-23, 1989; "Assessment and Valuation of External Environmental Damages."

New England Utility Rate Forum; Plymouth, Massachusetts, October 11, 1985; "Lessons from Massachusetts on Long Term Rates for QFs".

Massachusetts Energy Facilities Siting Council; Boston, Massachusetts, May 30, 1985; "Reviewing Utility Supply Plans".

National Association of State Utility Consumer Advocates; Williamstown, Massachusetts, August 13, 1984; "Power Plant Performance".

National Conference of State Legislatures; Boston, Massachusetts, August 6, 1984; "Utility Rate Shock".

National Governors' Association Working Group on Nuclear Power Cost Overruns; Washington, D.C., June 20, 1984; "Review and Modification of Regulatory and Rate Making Policy".

Annual Meeting of the American Association for the Advancement of Science, Session on Monitoring for Risk Management; Detroit, Michigan, May 27, 1983; "Insurance Market Assessment of Technological Risks".

REPORTS (excluding reports incorporated in testimony)

"The Agrea Project Critique of Externality Valuation: A Brief Rebuttal," March 1992.

"The Potential Economic Benefits of Regulatory NO_x Valuation for Clean Air Act Oxone Compliance in Massachusetts," March 1992.

"Report on the Adequacy of Ontario Hydro's Estimates of Externality Costs Associated with Electricity Exports," (with E. Caverhill), January 1991.

"Comments on the 1991-1992 Annual and Long Range Demand Side Management Plans of the Major Electric Utilities," (with Plunkett, J., et al.), September 1990.

"Power by Efficiency: An Assessment of Improving Electrical Efficiency to Meet Jamaica's Power Needs," (with Conservation Law Foundation, et al.), June 1990.

"Analysis of Fuel Substitution as an Electric Conservation Option," (with I.Goodman and E. Espenhorst), Boston Gas Company, December 22, 1989.

"The Development of Consistent Estimates of Avoided Costs for Boston Gas Company, Boston Edison Company, and Massachusetts Electric Company" (with E. Espenhorst), Boston Gas Company, December 22, 1989.

"The Valuation of Externalities from Energy Production, Delivery, and Use: Fall 1989 Update" (with E. Caverhill), Boston Gas Company, December 22, 1989.

"Conservation Potential in the State of Minnesota," (with I. Goodman) Minnesota Department of Public Service, June 16, 1988.

"Review of NEPOOL Performance Incentive Program," Massachusetts Energy Facilities Siting Council, April 12, 1988.

"Application of the DPU's Used-and-Useful Standard to Pilgrim 1" (With C. Wills and M. Meyer), Massachusetts Executive Office of Energy Resources, October 1987.

"Constructing a Supply Curve for Conservation: An Initial Examination of Issues and Methods," Massachusetts Energy Facilities Siting Council, June, 1985.

"Final Report: Rate Design Analysis," Pacific Northwest Electric Power and Conservation Planning Council, December 18, 1981.

ADVISORY ASSIGNMENTS TO REGULATORY COMMISSIONS

District of Columbia Public Service Commission, Docket No. 834, Phase II; Least-cost planning procedures and goals; August 1987 to March 1988.

Connecticut Department of Public Utility Control, Docket No. 87-07-01, Phase 2; Rate design and cost allocations; March 1988 to June 1989.

EXPERT TESTIMONY

In each entry, the following information is presented in order: jurisdiction and docket number; title of case; client; date testimony filed; and subject matter covered. Abbreviations of jurisdictions include: MDPU (Massachusetts Department of Public Utilities); MEFSC (Massachusetts Energy Facilities Siting Council); PSC (Public Service Commission); and PUC (Public Utilities Commission).

1. MEFSC 78-12/MDPU 19494, Phase I; Boston Edison 1978 forecast; Massachusetts Attorney General; June 12, 1978.

   Appliance penetration projections, price elasticity, econometric commercial forecast, peak demand forecast. Joint testimony with S.C. Geller.

2. MEFSC 78-17; Northeast Utilities 1978 forecast; Massachusetts Attorney General; September 29, 1978.

   Specification of economic/demographic and industrial models, appliance efficiency, commercial model structure and estimation.

3. MEFSC 78-33; Eastern Utilities Associates 1978 forecast; Massachusetts Attorney General; November 27, 1978.

   Household size, appliance efficiency, appliance penetration, price elasticity, commercial forecast, industrial trending, peak demand forecast.

4. MDPU 19494; Phase II; Boston Edison Company Construction Program; Massachusetts Attorney General; April 1, 1979.

   Review of numerous aspects of the 1978 demand forecasts of nine New England electric utilities, constituting 92% of projected regional demand growth, and of the NEPOOL demand forecast. Joint testimony with S.C. Geller.

5. MDPU 19494; Phase II; Boston Edison Company Construction Program; Massachusetts Attorney General; April 1, 1979.

   Reliability, capacity planning, capability responsibility allocation, customer generation, co-generation rates, reserve margins, operating reserve allocation. Joint testimony with S. Finger.

6. Atomic Safety and Licensing Board, Nuclear Regulatory Commission 50-471; Pilgrim Unit 2, Boston Edison Company; Commonwealth of Massachusetts; June 29, 1979.

   Review of the Oak Ridge National Laboratory and NEPOOL demand forecast models; cost-effectiveness of oil displacement; nuclear economics. Joint testimony with S.C. Geller.

7. MDPU 19845; Boston Edison Time-of-Use Rate Case; Massachusetts Attorney General; December 4, 1979.

   Critique of utility marginal cost study and proposed rates; principles of marginal cost principles, cost derivation, and rate design; options for reconciling costs and revenues. Joint testimony with S.C. Geller. Testimony eventually withdrawn due to delay in case.

8. MDPU 20055; Petition of Eastern Utilities Associates, New Bedford G. & E., and Fitchburg G.& E. to purchase additional shares of Seabrook Nuclear Plant; Massachusetts Attorney General; January 23, 1980.

   Review of demand forecasts of three utilities purchasing Seabrook shares; Seabrook power costs, including construction cost, completion date, capacity factor, O&M expenses, interim replacements, reserves and uncertainties; alternative energy sources, including conservation, cogeneration, rate reform, solar, wood and coal conversion.

9. MDPU 20248; Petition of MMWEC to Purchase Additional Share of Seabrook Nuclear Plant; Massachusetts Attorney General; June 2, 1980.

   Nuclear power costs; update and extension of MDPU 20055 testimony.

10. MDPU 200; Massachusetts Electric Company Rate Case; Massachusetts Attorney General; June 16, 1980.

    Rate design; declining blocks, promotional rates, alternative energy, demand charges, demand ratchets; conservation: master metering, storage heating, efficiency standards, restricting resistance heating.

11. MEFSC 79-33; Eastern Utilities Associates 1979 Forecast; Massachusetts Attorney General; July 16, 1980.

    Customer projections, consistency issues, appliance efficiency, new appliance types, commercial specifications, industrial data manipulation and trending, sales and resale.

12. MDPU 243; Eastern Edison Company Rate Case; Massachusetts Attorney General; August 19, 1980.

    Rate design: declining blocks, promotional rates, alternative energy, master metering.

13. Texas PUC 3298; Gulf States Utilities Rate Case; East Texas Legal Services; August 25, 1980.

    Inter-class revenue allocations, including production plant in-service, O&M, CWIP, nuclear fuel in progress, amortization of cancelled plant residential rate design; interruptible rates; off-peak rates. Joint testimony with M.B. Meyer.

14. MEFSC 79-1; Massachusetts Municipal Wholesale Electric Company Forecast; Massachusetts Attorney General; November 5, 1980.

    Cost comparison methodology; nuclear cost estimates; cost of conservation, cogeneration, and solar

15. MDPU 472; Recovery of Residential Conservation Service Expenses; Massachusetts Attorney General; December 12, 1980.

    Conservation as an energy source; advantages of per-kwh allocation over per-customer-month allocation.

16. MDPU 535; Regulations to Carry Out Section 210 of PURPA; Massachusetts Attorney General; January 26, 1981 and February 13, 1981.

    Filing requirements, certification, qualifying facility (QF) status, extent of coverage, review of contracts; energy rates; capacity rates; extra benefits of QFs in specific areas; wheeling; standardization of fees and charges.

17. MEFSC 80-17; Northeast Utilities 1980 Forecast; Massachusetts Attorney General; March 12, 1981 (not presented).

    Specification process, employment, electric heating promotion and penetration, commercial sales model, industrial model specification, documentation of price forecasts and wholesale forecast.

18. MDPU 558; Western Massachusetts Electric Company Rate Case; Massachusetts Attorney General; May, 1981.

    Rate design including declining blocks, marginal cost conservation impacts, and promotional rates. Conservation, including terms and conditions limiting renewable, cogeneration, small power production; scope of current conservation program; efficient insulation levels; additional conservation opportunities.

19. MDPU 1048; Boston Edison Plant Performance Standards; Massachusetts Attorney General; May 7, 1982.

    Critique of company approach, data, and statistical analysis; description of comparative and absolute approaches to standard-setting; proposals for standards and reporting requirements.

20. DCPSC FC785; Potomac Electric Power Rate Case; DC People's Counsel; July 29, 1982.

    Inter-class revenue allocations, including generation, transmission, and distribution plant classification; fuel and O&M classification; distribution and service allocators. Marginal cost estimation, including losses.

21. NHPUC DE1-312; Public Service of New Hampshire - Supply and Demand; Conservation Law Foundation, *et al.*; October 8, 1982.

    Conservation program design, ratemaking, and effectiveness. Cost of power from Seabrook nuclear plant, including construction cost and duration, capacity factor, O&M, replacements, insurance, and decommissioning.

22. Massachusetts Division of Insurance; Hearing to Fix and Establish 1983 Automobile Insurance Rates; Massachusetts Attorney General; October, 1982.

    Profit margin calculations, including methodology, interest rates, surplus flow, tax flows, tax rates, and risk premium.

23. Illinois Commerce Commission 82-0026; Commonwealth Edison Rate Case; Illinois Attorney General; October 15, 1982.

    Review of Cost-Benefit Analysis for nuclear plant. Nuclear cost parameters (construction cost, O&M, capital additions, useful like, capacity factor), risks, discount rates, evaluation techniques.

24. New Mexico Public Service Commission 1794; Public Service of New Mexico Application for Certification; New Mexico Attorney General; May 10, 1983.

    Review of Cost-Benefit Analysis for transmission line. Review of electricity price forecast, nuclear capacity factors, load forecast. Critique of company ratemaking proposals; development of alternative ratemaking proposal.

25. Connecticut Public Utility Control Authority 830301; United Illuminating Rate Case; Connecticut Consumers Counsel; June 17, 1983.

    Cost of Seabrook nuclear power plants, including construction cost and duration, capacity factor, O&M, capital additions, insurance and decommissioning.

26. MDPU 1509; Boston Edison Plant Performance Standards; Massachusetts Attorney General; July 15, 1983.

    Critique of company approach and statistical analysis; regression model of nuclear capacity factor; proposals for standards and for standard-setting methodologies.

27. Massachusetts Division of Insurance; Hearing to Fix and Establish 1984 Automobile Insurance Rates; Massachusetts Attorney General; October, 1983.

    Profit margin calculations, including methodology, interest rates.

28. Connecticut Public Utility Control Authority 83-07-15; Connecticut Light and Power Rate Case; Alloy Foundry; October 3, 1983.

    Industrial rate design. Marginal and embedded costs; classification of generation, transmission, and distribution expenses; demand versus energy charges.

29. MEFSC 83-24; New England Electric System Forecast of Electric Resources and Requirements; Massachusetts Attorney General; November 14, 1983, Rebuttal, February 2, 1984.

    Need for transmission line. Status of supply plan, especially Seabrook 2. Review of interconnection requirements. Analysis of cost-effectiveness for power transfer, line losses, generation assumptions.

30. Michigan PSC U-7775; Detroit Edison Fuel Cost Recovery Plan; Public Interest Research Group in Michigan; February 21, 1984.

    Review of proposed performance target for new nuclear power plant. Formulation of alternative proposals.

31. MDPU 84-25; Western Massachusetts Electric Company Rate Case; Massachusetts Attorney General; April 6, 1984.

    Need for Millstone 3. Cost of completing and operating unit, cost-effectiveness compared to alternatives, and its effect on rates. Equity and incentive problems created by CWIP. Design of Millstone 3 phase-in proposals to protect ratepayers: limitation of base-rate treatment to fuel savings benefit of unit.

32. MDPU 84-49 and 84-50; Fitchburg Gas & Electric Financing Case; Massachusetts Attorney General; April 13, 1984.

    Cost of completing and operating Seabrook nuclear units. Probability of completing Seabrook 2. Recommendations regarding FG&E and MDPU actions with respect to Seabrook.

33. Michigan PSC U-7785; Consumers Power Fuel Cost Recovery Plan; Public Interest Research Group in Michigan; April 16, 1984.

    Review of proposed performance targets for two existing and two new nuclear power plants. Formulation of alternative policy.

34. FERC ER81-749-000 and ER82-325-000; Montaup Electric Rate Cases; Massachusetts Attorney General; April 27, 1984.

    Prudence of Montaup and Boston Edison in decisions regarding Pilgrim 2 construction: Montaup's decision to participate, the Utilities' failure to review their earlier analyses and assumptions, Montaup's failure to question Edison's decisions, and the utilities' delay in canceling the unit.

35. Maine PUC 84-113; Seabrook 1 Investigation; Maine Public Advocate; September 13, 1984.

    Cost of completing and operating Seabrook Unit 1. Probability of completing Seabrook 1. Comparison of Seabrook to alternatives. Rate effects. Recommendations regarding utility and PUC actions with respect to Seabrook.

36. MDPU 84-145; Fitchburg Gas and Electric Rate Case; Massachusetts Attorney General; November 6, 1984.

    Prudence of Fitchburg and Public Service of New Hampshire in decision regarding Seabrook 2 construction: FGE's decision to participate, the utilities' failure to review their earlier analyses and assumptions, FGE's failure to question PSNH's decisions, and utilities' delay in halting construction and canceling the unit. Review of literature, cost and schedule estimate histories, cost-benefit analyses, and financial feasibility.

37. Pennsylvania PUC R-842651; Pennsylvania Power and Light Rate Case; Pennsylvania Consumer Advocate; November, 1984.

    Need for Susquehanna 2. Cost of operating unit, power output, cost-effectiveness compared to alternatives, and its effect on rates. Design of phase-in and excess capacity proposals to protect ratepayers: limitation of base-rate treatment to fuel savings benefit of unit.

38. NHPUC 84-200; Seabrook Unit 1 Investigation; New Hampshire Public Advocate; November 15, 1984.

    Cost of completing and operating Seabrook Unit 1. Probability of completing Seabrook 1. Comparison of Seabrook to alternatives. Rate and financial effects.

39. Massachusetts Division of Insurance; Hearing to Fix and Establish 1985 Automobile Insurance Rates; Massachusetts Attorney General; November, 1984.

    Profit margin calculations, including methodology and implementation.

40. MDPU 84-152; Seabrook Unit 1 Investigation; Massachusetts Attorney General; December 12, 1984.

    Cost of completing and operating Seabrook. Probability of completing Seabrook 1. Seabrook capacity factors.

41. Maine PUC 84-120; Central Maine Power Rate Case; Maine PUC Staff; December 11, 1984.

    Prudence of Central Maine Power and Boston Edison in decisions regarding Pilgrim 2 construction: CMP's decision to participate, the utilities' failure to review their earlier analyses and assumptions, CMP's failure to question Edison's decisions, and the utilities' delay in canceling the unit. Prudence of CMP in the planning and investment in Sears Island nuclear and coal plants. Review of literature, cost and schedule estimate histories, cost-benefit analyses, and financial feasibility.

42. Maine PUC 84-113; Seabrook 2 Investigation; Maine PUC Staff; December 14, 1984.

    Prudence of Maine utilities and Public Service of New Hampshire in decisions regarding Seabrook 2 construction: decisions to participate and to increase ownership share, the utilities' failure to review their earlier analyses and assumptions, failure to question PSNH's decisions, and the utilities' delay in halting construction and canceling the unit. Review of literature, cost and schedule estimate histories, cost-benefit analyses, and financial feasibility.

43. MDPU 1627; Massachusetts Municipal Wholesale Electric Company Financing Case; Massachusetts Executive Office of Energy Resources; January 14, 1985.

    Cost of completing and operating Seabrook nuclear unit 1. Cost of conservation and other alternatives to completing Seabrook. Comparison of Seabrook to alternatives.

44. Vermont PSB 4936; Millstone 3; Costs and In-Service Date; Vermont Department of Public Service; January 21, 1985.

    Construction schedule and cost of completing Millstone Unit 3.

45. MDPU 84-276; Rules Governing Rates for Utility Purchases of Power from Qualifying Facilities; Massachusetts Attorney General; March 25, 1985, and October 18, 1985.

    Institutional and technological advantages of Qualifying Facilities. Potential for QF development. Goals of QF rate design. Parity with other power sources. Security requirements. Projecting avoided costs. Capacity credits. Pricing options. Line loss corrections.

46. MDPU 85-121; Investigation of the Reading Municipal Light Department; Wilmington (MA) Chamber of Commerce; November 12, 1985.

Calculation on return on investment for municipal utility. Treatment of depreciation and debt for ratemaking. Geographical discrimination in streetlighting rates. Relative size of voluntary payments to Reading and other towns. Surplus and disinvestment. Revenue allocation.

47. Massachusetts Division of Insurance; Hearing to Fix and Establish 1986 Automobile Insurance Rates; Massachusetts Attorney General and State Rating Bureau; November, 1985.

Profit margin calculations, including methodology, implementation, modeling of investment balances, income, and return to shareholders.

48. New Mexico Public Service Commission 1833, Phase II; El Paso Electric Rate Case; New Mexico Attorney General; December 23, 1985.

Nuclear decommissioning fund design. Internal and external funds; risk and return; fund accumulation, recommendations. Interim performance standard for Palo Verde nuclear plant.

49. Pennsylvania PUC R-850152; Philadelphia Electric Rate Case; Utility Users Committee and University of Pennsylvania; January 14, 1986.

Limerick 1 rate effects. Capacity benefits, fuel savings, operating costs, capacity factors, and net benefits to ratepayers. Design of phase-in proposals.

50. MDPU 85-270; Western Massachusetts Electric Rate Case; Massachusetts Attorney General; March 19, 1986.

Prudence of Northeast Utilities in generation planning related to Millstone 3 construction: decisions to start and continue construction, failure to reduce ownership share, failure to pursue alternatives. Review of industry literature, cost and schedule histories, and retrospective cost-benefit analyses.

51. Pennsylvania PUC R-850290; Philadelphia Electric Auxiliary Service Rates; Albert Einstein Medical Center, University of Pennsylvania and AMTRAK; March 24, 1986.

Review of utility proposals for supplementary and backup rates for small power producers and cogenerators. Load diversity, cost of peaking capacity, value of generation, price signals, and incentives. Formulation of alternative supplementary rate.

52. New Mexico Public Service Commission 2004; Public Service of New Mexico, Palo Verde Issues; New Mexico Attorney General; May 7, 1986.

    Recommendations for Power Plant Performance Standards for Palo Verde nuclear units 1, 2, and 3.

53. Illinois Commerce Commission 86-0325; Iowa-Illinois Gas and Electric Co. Rate Investigation; Illinois Office of Public Counsel; August 13, 1986.

    Determination of excess capacity based on reliability and economic concerns. Identification of specific units associated with excess capacity. Required reserve margins.

54. New Mexico Public Service Commission 2009; El Paso Electric Rate Moderation Program; New Mexico Attorney General; August 18, 1986. (Not presented).

    Prudence of EPE in generation planning related to Palo Verde nuclear construction, including failure to reduce ownership share and failure to pursue alternatives. Review of industry literature, cost and schedule histories, and retrospective cost-benefit analyses.

    Recommendation for rate-base treatment; proposal of power plant performance standards.

55. City of Boston, Public Improvements Commission; Transfer of Boston Edison District Heating Steam System to Boston Thermal Corporation; Boston Housing Authority; December 18, 1986.

    History and economics of steam system; possible motives of Boston Edison in seeking sale; problems facing Boston Thermal; information and assurances required prior to Commission approval of transfer.

56. Massachusetts Division of Insurance; Hearing to Fix and Establish 1987 Automobile Insurance Rates; Massachusetts Attorney General and State Rating Bureau; December 1986 and January 1987.

    Profit margin calculations, including methodology, implementation, derivation of cashflows, installment income, income tax status, and return to shareholders.

57. MDPU 87-19; Petition for Adjudication of Development Facilitation Program; Hull (MA) Municipal Light Plant; January 21, 1987.

    Estimation of potential load growth; cost of generation, transmission, and distribution additions. Determination of hook-up charges. Development of residential load estimation procedure reflecting appliance ownership, dwelling size.

58. New Mexico Public Service Commission 2004; Public Service of New Mexico Nuclear Decommissioning Fund; New Mexico Attorney General; February 19, 1987.

Decommissioning cost and likely operating life of nuclear plants. Review of utility funding proposal. Development of alternative proposal. Ratemaking treatment.

59. MDPU 86-280; Western Massachusetts Electric Rate Case; Massachusetts Energy Office; March 9, 1987.

Marginal cost rate design issues. Superiority of long-run marginal cost over short-run marginal cost as basis for rate design. Relationship of consumer reaction, utility planning process, and regulatory structure to rate design approach. Implementation of short-run and long-run rate designs. Demand versus energy charges, economic development rates, spot pricing.

60. Massachusetts Division of Insurance 87-9; 1987 Workers' Compensation Rate Filing; State Rating Bureau; May 1987.

Profit margin calculations, including methodology, implementation, surplus requirements, investment income, and effects of 1986 Tax Reform Act.

61. Texas PUC 6184; Economic Viability of South Texas Nuclear Plant #2; Committee for Consumer Rate Relief; August 17, 1987.

STNP operating parameter projections; capacity factor, O&M, capital additions, decommissioning, useful life. STNP 2 cost and schedule projections. Potential for conservation.

62. Minnesota PUC ER-015/GR-87-223; Minnesota Power Rate Case; Minnesota Department of Public Service; August 17, 1987.

Excess capacity on MP system; historical, current, and projected. Review of MP planning prudence prior to and during excess; efforts to sell capacity. Cost of excess capacity. Recommendations for ratemaking treatment.

63. Massachusetts Division of Insurance 87-27; 1988 Automobile Insurance Rates; Massachusetts Attorney General and State Rating Bureau; September 2, 1987. Rebuttal October 8, 1987.

Underwriting profit margins. Effect of 1986 Tax Reform Act. Biases in calculation of average margins.

64. MDPU 88-19; Power Sales Contract from Riverside Steam and Electric to Western Massachusetts Electric; Riverside Steam and Electric; November 4, 1987.

Comparison of risk from QF contract and utility avoided cost sources. Risk of oil dependence. Discounting cash flows to reflect risk.

65. Massachusetts Division of Insurance 87-53; 1987 Workers' Compensation Rate Refiling; State Rating Bureau; December 14, 1987.

Profit margin calculations, including updating of data, compliance with Commissioner's order, treatment of surplus and risk, interest rate calculation, and investment tax rate calculation.

66. Massachusetts Division of Insurance; 1987 and 1988 Automobile Insurance Remand Rates; Massachusetts Attorney General and State Rating Bureau; February 5, 1988.

Underwriting profit margins. Provisions for income taxes on finance charges. Relationships between allowed and achieved margins, between statewide and nationwide data, and between profit allowances and cost projections.

67. Massachusetts Department of Public Utilities 86-36; Investigation into the Pricing and Ratemaking Treatment to be Afforded New Electric Generating Facilities which are not Qualifying Facilities; Conservation Law Foundation; May 2, 1988.

Cost recovery for utility conservation programs. Compensating for lost revenues. Utility incentive structures.

68. Massachusetts Department of Public Utilities 88-123; Petition of Riverside Steam & Electric Company; Riverside Steam and Electric Company; May 18, 1988, and November 8, 1988.

Estimation of avoided costs of Western Massachusetts Electric Company. Nuclear capacity factor projections and effects on avoided costs. Avoided cost of energy interchange and power plant life extensions. Differences between median and expected oil prices. Salvage value of cogeneration facility. Off-system energy purchase projections. Reconciliation of avoided cost projection.

69. Massachusetts Department of Public Utilities 88-67; Boston Gas Company; Boston Housing Authority; June 17, 1988.

Estimation of annual avoidable costs, 1988 to 2005, and levelized avoided costs. Determination of cost recovery and carrying costs for conservation investments. Standards for assessing conservation cost-effectiveness. Evaluation of cost-effectiveness of utility funding of proposed natural gas conservation measures.

70. Rhode Island Public Utility Commission Docket 1900; Providence Water Supply Board Tariff Filing; Conservation Law Foundation, Audubon Society of Rhode Island, and League of Women Voters of Rhode Island; June 24, 1988.

Estimation of avoidable water supply costs. Determination of costs of water conservation. Conservation cost-benefit analysis.

71. Massachusetts Division of Insurance 88-22; 1989 Automobile Insurance Rates; Massachusetts Attorney General and State Rating Bureau; Profit Issues August 12, 1988, supplemented August 19, 1988; Losses and Expenses September 16, 1988.

Underwriting profit margins. Effects of 1986 Tax Reform Act. Taxation of common stocks. Lag in tax payments. Modeling risk and return over time. Treatment of finance charges. Comparison of projected and achieved investment returns.

72. Vermont Public Service Board Docket No. 5270, Module 6; Investigation into Least-Cost Investments, Energy Efficiency, Conservation, and the Management of Demand for Energy; Conservation Law Foundation, Vermont Natural Resources Council, and Vermont Public Interest Research Group; September 26, 1988.

Cost recovery for utility conservation programs. Compensation of utilities for revenue losses and timing differences. Incentive for utility participation.

73. Vermont House of Representatives, Natural Resources Committee; House Act 130; "Economic Analysis of Vermont Yankee Retirement"; Vermont Public Interest Research Group; February 21, 1989.

Projection of capacity factors, operating and maintenance expense, capital additions, overhead, replacement power costs, and net costs of Vermont Yankee.

74. MDPU 88-67, Phase II; Boston Gas Company Conservation Program and Rate Design; Boston Gas Company; March 6, 1989.

Estimation of avoided gas cost; treatment of non-price factors; estimation of externalities; identification of cost-effective conservation.

75. Vermont Public Service Board Docket No. 5270; Status Conference on Conservation and Load Management Policy Settlement; Central Vermont Public Service, Conservation Law Foundation, Vermont Natural Resources Council, Vermont Public Interest Research Group, and Vermont Department of Public Service; May 1, 1989.

Cost-benefit test for utility conservation programs. Role of externalities. Cost recovery concepts and mechanisms. Resource allocations, cost allocations, and equity considerations. Guidelines for conservation preapproval mechanisms. Incentive mechanisms and recovery of lost revenues.

76. Boston Housing Authority Court 05099; Gallivan Boulevard Task Force vs. Boston Housing Authority, *et al.;* Boston Housing Authority; June 16, 1989.

Effect of master-metering on consumption of natural gas and electricity. Legislative and regulatory mandates regarding conservation.

77. MDPU 89-100; Boston Edison Rate Case; Massachusetts Energy Office; June 30, 1989.

Prudence of BECo's decision of spend $400 million from 1986-88 on returning the Pilgrim nuclear power plant to service. Projections of nuclear capacity factors, O&M, capital additions, and overhead. Review of decommissioning cost, tax effect of abandonment, replacement power cost, and plant useful life estimates. Requirements for prudence and used-and-useful analyses.

78. MDPU 88-123; Petition of Riverside Steam and Electric Company; Riverside Steam and Electric; July 24, 1989. Rebuttal, October 3, 1989.

Reasonableness of Northeast Utilities' 1987 avoided cost estimates. Projections of nuclear capacity factors, economy purchases, and power plant operating life. Treatment of avoidable energy and capacity costs and of off-system sales. Expected versus reference fuel prices.

79. MDPU 89-72; Statewide Towing Association, Police-Ordered Towing Rates; Massachusetts Automobile Rating Bureau; September 13, 1989.

Review of study supporting proposed increase in towing rates. Critique of study sample and methodology. Comparison to competitive rates. Supply of towing services. Effects of joint products and joint sales on profitability of police-ordered towing. Joint testimony with I. Goodman.

80. Vermont Public Service Board Docket 5330; Application of Vermont Utilities for Approval of a Firm Power and Energy Contract with Hydro-Quebec; Conservation Law Foundation, Vermont Natural Resources Council, Vermont Public Interest Research Group; December 19, 1989. Surrebuttal February 6, 1990.

Analysis of a proposed 450-MW, 20 year purchase of Hydro-Quebec power by twenty-four Vermont utilities. Comparison to efficiency investment in Vermont, including potential for efficiency savings. Analysis of Vermont electric energy supply. Identification of possible improvements to proposed contract.

Critique of conservation potential analysis. Planning risk of large supply additions. Valuation of environmental externalities.

81. MDPU 89-239; Inclusion of Externalities in Energy Supply Planning, Acquisition and Dispatch for Massachusetts Utilities; December, 1989; April, 1990; May, 1990.

Critique of Division of Energy Resources report on externalities. Methodology for evaluating external costs. Proposed values for environmental and economic externalities of fuel supply and use.

82. California Public Utilities Commission; Incorporation of Environmental Externalities in Utility Planning and Pricing; Coalition of Energy Efficient and Renewable Technologies; February 21, 1990.

Approaches for valuing externalities for inclusion in setting power purchase rates. Effect of uncertainty on assessing externality values.

83. Illinois Commerce Commission Docket 90-0038; Proceeding to Adopt a Least Cost Electric Energy Plan for Commonwealth Edison Company; City of Chicago; May 25, 1990. Joint rebuttal testimony with David Birr, August 14, 1990.

Problems in Commonwealth Edison's approach to demand-side management. Potential for cost-effective conservation. Valuing externalities in least-cost planning.

84. Maryland Public Service Commission Case No. 8278; Adequacy of Baltimore Gas & Electric's Integrated Resource Plan; Maryland Office of People's Counsel; September 18, 1990.

Rationale for demand-side management, and BG&E's problems in approach to DSM planning. Potential for cost-effective conservation. Valuation of environmental externalities. Recommendations for short-term DSM program priorities.

85. Indiana Utility Regulatory Commission; Integrated Resource Planning Docket; Indiana Office of Utility Consumer Counselor; November 1, 1990.

Integrated resource planning process and methodology, including externalities and screening tools. Incentives, screening, and evaluation of demand-side management. Potential of resource bidding in Indiana.

86. MDPU Dockets 89-141, 90-73, 90-141, 90-194, and 90-270; Preliminary Review of Utility Treatment of Environmental Externalities in October QF Filings; Boston Gas Company; November 5, 1990.

Generic and specific problems in Massachusetts utilities' RFPs with regard to externality valuation requirements. Recommendations for corrections.

87. MEFSC 90-12/90-12A; Adequacy of Boston Edison Proposal to Build Combined-Cycle Plant; Conservation Law Foundation; December 14, 1990.

    Problems in Boston Edison's treatment of demand-side management, supply option analysis, and resource planning. Recommendations of mitigation options.

88. Maine PUC Docket No. 90-286; Adequacy of Conservation Program of Bangor Hydro Electric; Penobscot River Coalition; February 19, 1991.

    Role of utility-sponsored DSM in least-cost planning. Bangor Hydro's potential for cost-effective conservation. Problems with Bangor Hydro's assumptions about customer investment in energy efficiency measures.

89. Commonwealth of Virginia State Corporation Commission Case No. PUE900070; Order Establishing Commission Investigation; Southern Environmental Law Center; March 6, 1991.

    Role of utilities in promoting energy efficiency. Least-cost planning objectives of and resource acquisition guidelines for DSM. Ratemaking considerations for DSM investments.

90. Massachusetts DPU Docket No. 90-261-A; Economics and Role of Fuel-Switching in the DSM Program of the Massachusetts Electric Company; Boston Gas Company; April 17, 1991.

    Role of fuel-switching in utility DSM programs and specifically in Massachusetts Electric's. Establishing comparable avoided costs and comparison of electric and gas system costs. Updated externality values.

91. Commonwealth of Massachusetts; Massachusetts Refusetech Contractual Request for Adjustment to Service Fee; Massachusetts Refusetech; May 13, 1991.

    NEPCo rates for power purchases from the NESWC plant. Fuel price and avoided cost projections vs. realities.

92. Vermont PSB Docket No. 5491; Cost-Effectiveness of Central Vermont's Commitment to Hydro Quebec Purchases; Conservation Law Foundation; July 19, 1991.

    Changes in load forecasts and resale markets since approval of HQ purchases. Effect of HQ purchase on DSM.

93. South Carolina Public Service Commission Docket No. 91-216-E; Cost Recovery of Duke Power's DSM Expenditures; South Carolina Department of Consumer Affairs; September 13, 1991. Surrebuttal October 2, 1991.

    Problems with conservation plans of Duke Power, including load building, cream skimming, and inappropriate rate designs.

94. Maryland Public Service Commission Case No. 8241, Phase II; Review of Baltimore Gas & Electric's Avoided Costs; Maryland Office of People's Counsel; September 19, 1991.

    Development of direct avoided costs for DSM. Problems with BG&E's avoided costs and DSM screening. Incorporation of environmental externalities.

95. Bucksport Planning Board; AES/Harriman Cove Shoreland Zoning Application; Conservation Law Foundation and Natural Resources Council of Maine; October 1, 1991.

    New England's power surplus. Costs of bringing AES/Harriman Cove on line to back out existing generation. Alternatives to AES.

96. Massachusetts DPU Docket No. 91-131; Update of Externalities Values Adopted in Docket 89-239; Boston Gas Company; October 4, 1991. Rebuttal December 13, 1991.

    Updates on pollutant externality values. Addition of values for chlorofluorocarbrons, air toxics, thermal pollution, and oil import premium. Review of state regulatory actions regarding externalities.

97. Florida PSC Docket No. 910759; Petition of Florida Power Corporation for Determination of Need for Proposed Electrical Power Plant and Related Facilities; Floridians for Responsible Utility Growth; October 21, 1991.

    Florida Power's obligation to pursue integrated resource planning and failure to establish need for proposed facility. Methods to increase scope and scale of demand-side investment.

98. Florida PSC Docket No. 910833-EI; Petition of Tampa Electric Company for a Determination of Need for Proposed Electrical Power Plant and Related Facilities; Floridians for Responsible Utility Growth; October 31, 1991.

    Tampa Electric's obligation to pursue integrated resource planning and failure to establish need for proposed facility. Methods to increase scope and scale of demand-side investment.

99. Pennsylvania PUC Dockets I-900005, R-901880; Investigation into Demand Side Management by Electric Utilities; Pennsylvania Energy Office; January 10, 1992.

    Appropriate cost recovery mechanism for Pennsylvania utilities. Purpose and scope of direct cost recovery, lost revenue recovery, and incentives.

100. South Carolina PSC Docket No. 91-606-E; Petition of South Carolina Electric and Gas for a Certificate of Public Convenience and Necessity for a Coal-Fired Plant; South Carolina Department of Consumer Affairs; January 20, 1992.

    Justification of plant certification under integrated resource planning. Failures in SCE&G's DSM planning and company potential for demand-side savings.

101. Massachusetts DPU Docket No. 92-92; Adequacy of Boston Edison's Streetlighting Options; Town of Lexington; June 22, 1992.

    Efficiency and quality of streetlighting options. Boston Edison's treatment of high-quality streetlighting. Corrected rate proposal for the Daylux lamp. Ownership of public streetlighting.

102. South Carolina PSC Docket No. 92-208-E; Integrated Resource Plan of Duke Power Company; South Carolina Department of Consumer Affairs; August 4, 1992.

    Problems with Duke Power's DSM screening process, estimation of avoided cost, DSM program design, and integration of demand-side and supply-side planning.

103. North Carolina Utilities Commission Docket No. E-100, Sub 64; Integrated Resource Planning Docket; Southern Environmental Law Center; September 29, 1992.

    General principles of integrated resource planning, DSM screening, and program design. Review of the IRP's of Duke Power Company, Carolina Power & Light Company, and North Carolina Power.

Attachment 2: Comparison of the Cost of the Warrior Run Contract to Levelized APS Avoided Costs for DSM

		Warrior Run Annual cost to APS $10^6 [1]	Avoided energy c/kWh [2]	Avoided capacity $/kW [3]	Avoided energy $10^6 [4]	Avoided capacity $10^6 [5]	Sum of avoided energy, capacity $10^6 [6]
	1993						
	1994						
	1995						
0	1996	$22.20	$0.73	$17.80	$8.08	$3.20	$11.29
1	1997	$90.20	$2.91	$71.21	$32.33	$12.82	$45.14
2	1998	$92.30	$2.91	$71.21	$32.33	$12.82	$45.14
3	1999	$95.00	$2.91	$71.21	$32.33	$12.82	$45.14
4	2000	$97.70	$2.91	$71.21	$32.33	$12.82	$45.14
5	2001	$100.10	$2.91	$71.21	$32.33	$12.82	$45.14
6	2002	$102.70	$2.91	$71.21	$32.33	$12.82	$45.14
7	2003	$105.10	$2.91	$71.21	$32.33	$12.82	$45.14
8	2004	$107.80	$2.91	$71.21	$32.33	$12.82	$45.14
9	2005	$110.60	$2.91	$71.21	$32.33	$12.82	$45.14
10	2006	$113.50	$2.91	$71.21	$32.33	$12.82	$45.14
11	2007	$116.70	$2.91	$71.21	$32.33	$12.82	$45.14
12	2008	$119.80	$2.91	$71.21	$32.33	$12.82	$45.14
13	2009	$122.80	$2.91	$71.21	$32.33	$12.82	$45.14
14	2010	$126.20	$2.91	$71.21	$32.33	$12.82	$45.14
15	2011	$129.60	$2.91	$71.21	$32.33	$12.82	$45.14
16	2012	$133.10	$2.91	$71.21	$32.33	$12.82	$45.14
17	2013	$136.60	$2.91	$71.21	$32.33	$12.82	$45.14
18	2014	$140.30	$2.91	$71.21	$32.33	$12.82	$45.14
19	2015	$144.00	$2.91	$71.21	$32.33	$12.82	$45.14
20	2016	$147.90	$2.91	$71.21	$32.33	$12.82	$45.14
21	2017	$152.00	$2.91	$71.21	$32.33	$12.82	$45.14
22	2018	$156.00	$2.91	$71.21	$32.33	$12.82	$45.14
23	2019	$160.20	$2.91	$71.21	$32.33	$12.82	$45.14
24	2020	$164.50	$2.91	$71.21	$32.33	$12.82	$45.14
25	2021	$169.10	$2.91	$71.21	$32.33	$12.82	$45.14
26	2022	$173.60	$2.91	$71.21	$32.33	$12.82	$45.14
	2023	$178.30	$2.91	$71.21	$32.33	$12.82	$45.14
1	2024	$183.10	$2.91	$71.21	$32.33	$12.82	$45.14
2	2025	$198.10	$2.91	$71.21	$32.33	$12.82	$45.14
3	2026	$193.20	$2.91	$71.21	$32.33	$12.82	$45.14
Discount rate:			11.2%				
PV(1993$)		$712.61	$18.64	$456.20			$289.20
[7]: additional cost of Warrior Run to ratepayers:							$423.40

Notes:

[1]: from spreadsheet AES Warrior Run provided in response to Westvaco data request #1.

[2]: levelized avoided energy cost, from APS IRP, p. 335.

[3]: levelized avoided capacity cost, from APS IRP, p. 334.

[4]: [2] * 180 MW; 180 MW is the Warrior Run capacity.

[5]: [3] * average annual generation of warrior run; from IRP, p. 467.

[6]: [4] + [5].

[7]: pv of [1] – pv of [6].

Costs in 1996 in columns [2] through [6] are 1/4 of costs in 1997, to reflect the fact that Warrior Run would only operate in the last quarter of 1996.

Discount rate from IRP, p. 11.

Attachment 3: Comparison of the Cost of the Warrior Run Contract to an Approximation of Annual APS Avoided Costs for DSM

		Warrior Run Annual cost to APS $10^6 [1]	Avoided energy c/kWh [2]	Avoided capacity $/kW [3]	Avoided energy $10^6 [4]	Avoided capacity $10^6 [5]	Sum of avoided energy, capacity [6]	Difference bet. Warrior Run cost avoided costs, [7]
	1993							
	1994							
	1995							
0	1996	$22.20	$0.61	$12.51	$6.78	$2.25	$9.03	$13.17
1	1997	$90.20	$2.44	$50.04	$27.10	$9.01	$36.11	$54.09
2	1998	$92.30	$2.44	$50.04	$27.10	$9.01	$36.11	$56.19
3	1999	$95.00	$2.44	$50.04	$27.10	$9.01	$36.11	$58.89
4	2000	$97.70	$2.44	$50.04	$27.10	$9.01	$36.11	$61.59
5	2001	$100.10	$2.44	$50.04	$27.10	$9.01	$36.11	$63.99
6	2002	$102.70	$2.44	$50.04	$27.10	$9.01	$36.11	$66.59
7	2003	$105.10	$2.44	$50.04	$27.10	$9.01	$36.11	$68.99
8	2004	$107.80	$2.44	$50.04	$27.10	$9.01	$36.11	$71.69
9	2005	$110.60	$2.44	$50.04	$27.10	$9.01	$36.11	$74.49
10	2006	$113.50	$2.44	$50.04	$27.10	$9.01	$36.11	$77.39
11	2007	$116.70	$3.66	$113.71	$40.61	$20.47	$61.07	$55.63
12	2008	$119.80	$3.66	$113.71	$40.61	$20.47	$61.07	$58.73
13	2009	$122.80	$3.66	$113.71	$40.61	$20.47	$61.07	$61.73
14	2010	$126.20	$3.66	$113.71	$40.61	$20.47	$61.07	$65.13
15	2011	$129.60	$3.66	$113.71	$40.61	$20.47	$61.07	$68.53
16	2012	$133.10	$4.71	$91.71	$52.32	$16.51	$68.83	$64.27
17	2013	$136.60	$4.71	$91.71	$52.32	$16.51	$68.83	$67.77
18	2014	$140.30	$4.71	$91.71	$52.32	$16.51	$68.83	$71.47
19	2015	$144.00	$4.71	$91.71	$52.32	$16.51	$68.83	$75.17
20	2016	$147.90	$4.71	$91.71	$52.32	$16.51	$68.83	$79.07
21	2017	$152.00	$3.72	$156.40	$41.35	$28.15	$69.50	$82.50
22	2018	$156.00	$3.72	$156.40	$41.35	$28.15	$69.50	$86.50
23	2019	$160.20	$3.72	$156.40	$41.35	$28.15	$69.50	$90.70
24.	2020	$164.50	$3.72	$156.40	$41.35	$28.15	$69.50	$95.00
25	2021	$169.10	$3.72	$156.40	$41.35	$28.15	$69.50	$99.60
26	2022	$173.60	$3.72	$156.40	$41.35	$28.15	$69.50	$104.10
27	2023	$178.30	$3.72	$156.40	$41.35	$28.15	$69.50	$108.80
28	2024	$183.10	$3.72	$156.40	$41.35	$28.15	$69.50	$113.60
29	2025	$198.10	$3.72	$156.40	$41.35	$28.15	$69.50	$128.60
30	2026	$193.20	$3.72	$156.40	$41.35	$28.15	$69.50	$123.70
Discount rate:			11.2%					
PV(1993$)		$712.61	$18.64	$456.20			$289.20	
[8]: additional cost of Warrior Run to ratepayers:							$423.40	

Notes:
[1]: from spreadsheet AES Warrior Run provided in response to Westvaco data request #1.
[2]: levelized avoided energy cost, from APS IRP, p. 335.
[3]: levelized avoided capacity cost, from APS IRP, p. 334.
[4]: [2] * 180 MW; 180 MW is the Warrior Run capacity.
[5]: [3] * average annual generation of warrior run; from IRP, p. 467.
[6]: [4] + [5].
[7]: [1] − [6].
[8]: pv of [1] − pv of [6].
Costs in 1996 in columns [2] through [6] are 1/4 of costs in 1997, to reflect the fact that Warrior Run would only operate in the last quarter of 1996.
Discount rate from IRP, p. 11.

Attachment 4: Correction of AES Evaluation of Warrior Run Cost–Effectiveness

AES Warrior Run revenue requirements are based upon the current electric contract between AES and Potomac Edison, as well as current PE cost and escalation assumptions.

Note: a 70.4% capacity factor was assumed for Warrior Run, 15% for Combined Cycle, in order to be consistent with PE's representation of the AES Warrior Run project in their Integrated Resource Plan (reference Volume 1, pg 467)

Total Revenue Requirements ($MM) Associated with AES Warrior Run Project (1997)	0	0	0	0	22.2	90.2	92.3	95.0	97.7	100.1	102.7	105.1	107.8	110.6
Required Revenue Calculation for Utility CT/CC Build Option														
CT (1997–1999)	W 92–93													
						1	2	3	4	5	6	7	8	9
Utility CT Unit Revenue Requirements ($MM)	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Fixed Capacity	0	0	0	0	0	11.8	11.5	11.0	10.6	10.2	9.8	9.4	9.1	8.7
Variable Operating Expenses	0	0	0	0	0	3.2	3.5	3.9	0.0	0.0	0.0	0.0	0.0	0.0
Total Required Revenue	0.0	0.0	0.0	0.0	0.0	15.0	15.0	14.9	10.6	10.2	9.8	9.4	9.1	8.7
Fixed Capacity for Deferred CT									13.3	11.5	11.0	10.6	10.2	9.8
Utility Added Intermediate Load Rev. Req. ($MM)	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Total Var. Oper. Required Revenue	0	0	0	0	0	19.2	19.8	20.4	18.1	19.0	19.9	20.9	21.9	22.9
CC unit (2000–2026)														
									1	2	3	4	5	6
Utility CC Unit Revenue Requirements ($MM)	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Return on Capital	0	0	0	0	0	0	0	0	14	13.0	12.3	11.6	11.0	10.3
Fuel Purchases	0	0	0	0	0	0	0	0	17.0	18.5	20.2	22.0	23.6	25.3
Variable O&M	0	0	0	0	0	0	0	0	0.4	0.4	0.4	0.4	0.4	0.5
Depreciation & Amortization	0	0	0	0	0	0	0	0	6.1	6.1	6.1	6.1	6.1	6.1
Fixed O&M Expenses	0	0	0	0	0	0	0	0	0.2	0.2	0.2	0.3	0.3	0.3
Income Tax	0	0	0	0	0	0	0	0	5.0	4.8	4.5	4.3	4.0	3.8
Utility CC Unit Total Required Revenue	0	0	0	0	0	0	0	0	42.5	43.1	43.9	44.7	45.5	46.3
Total Required Revenue for Utility CT/CC Build Option (CT/Int. 1997–1999; CC 2000–2026)	0	0	0	0	0	34.2	34.7	35.3	57.9	60.8	62.6	64.4	66.2	68.1
Net Cost of Warrior Run					22.2	56.0	57.6	59.7	39.8	39.3	40.1	40.7	41.6	42.5
Cummulative Present Value at 11.2% (1993$)						58.7	96.3	131.5	152.5	171.2	188.4	204.0	218.4	231.6
									1					
CC ASSET IN SERVICE	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Total Asset at end of year	0	0	0	0	0	0	0	0	111.4	105.8	100.2	94.7	89.1	83.5
Depreciation	0	0	0	0	0	0	0	0	5.6	5.6	5.6	5.6	5.6	5.6
CC AFUDC IN RATE BASE														
Beginning AFUDC	* est. based on 2 yr const.			0	0	0	0	0	11.1	10.5	10.0	9.4	8.9	8.3
Amortization of AFUDC	at 11.2% wtd cost of cap.			0	0	0	0	0	0.6	0.6	0.6	0.6	0.6	0.6
Return on unamortized AFUDC				0	0	0	0	0	1.2	1.2	1.1	1.1	0	0.9

113.5	116.7	119.8	122.8	126.2	129.6	133.1	136.6	140.3	144.0	147.9	152.0	156.0	160.2	164.5	169.1	173.6	178.3	183.1	188.1	193.2
10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
8.4	8.0	7.7	7.3	7.0	6.6	6.3	5.9	5.6	5.2	4.9	4.5	4.3	4.1	3.9	3.7	3.5	3.3	3.1	2.9	2.7
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8.4	8.0	7.7	7.3	7.0	6.6	6.3	5.9	5.6	5.2	4.9	4.5	4.3	4.1	3.9	3.7	3.5	3.3	3.1	2.9	2.7
9.4	9.1	8.7	8.4	8.0	7.7	7.3	7.0	6.6	6.3	5.9	5.6	5.2	4.9	4.5	4.3	4.1	3.9	3.7	3.5	3.3
2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
24.1	25.2	26.5	27.7	29.1	30.5	32.0	33.6	35.2	36.9	38.7	40.6	42.5	44.6	46.8	49.1	51.4	53.9	56.6	59.3	62.2
7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27
2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
9.6	8.9	8.2	7.5	6.9	6.2	5.5	4.8	4.1	3.4	2.7	2.1	1.4	0.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0
27.2	29.2	31.2	33.2	35.2	37.6	40.2	43.0	46.0	49.1	52.5	56.2	60.0	64.2	68.6	73.3	78.4	83.8	89.6	95.8	102.4
0.5	0.5	0.5	0.5	0.6	0.6	0.6	0.7	0.7	0.7	0.7	0.8	0.8	0.9	0.9	0.9	1.0	1.0	1.1	1.1	1.2
6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.6	0.6	0.6	0.6	0.7	0.7	0.7
3.5	3.3	3.0	2.8	2.5	2.3	2.0	1.8	1.5	1.3	1.0	0.8	0.5	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0
47.2	48.3	49.4	50.5	51.6	53.2	54.9	56.7	58.8	61.1	63.6	66.4	69.4	72.6	70.1	74.9	80.0	85.5	91.3	97.6	104.3
70.2	72.5	74.8	77.2	79.7	82.6	85.8	89.3	93.0	97.0	101.3	105.9	110.9	116.4	116.2	123.3	130.8	138.8	147.3	156.3	165.9
43.3	44.2	45.0	45.6	46.5	47.0	47.3	47.3	47.3	47.0	46.6	46.1	45.1	43.8	48.3	45.8	42.8	39.5	35.8	31.8	27.3
243.7	254.9	265.0	274.3	282.8	290.5	297.5	303.8	309.5	314.6	319.1	323.1	326.6	329.7	332.8	335.4	337.6	339.4	340.8	342.0	342.9
													20							
2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
78.0	72.4	66.8	61.2	55.7	50.1	44.5	39.0	33.4	27.8	22.3	16.7	11.1	5.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0
													20							
7.8	7.2	6.7	6.1	5.6	5.0	4.4	3.9	3.3	2.8	2.2	1.7	1.1	0.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.9	0.8	0.7	0.7	0.6	0.6	0.5	0.4	0.4	0.3	0.2	0.2	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Attachment 4: Correction of AES Evaluation of Warrior Run Cost–Effectiveness

Project Assumptions:		Source and/or explanation:
Net Output (MW)	180	IRP Vol.1, pg 467
Capital Cost CC (1997$/kw)	850	AES assumption
Capital Cost CT (1997$/kw)	300	AES assumption
APS Construction Esc.	4.0%	IRP Vol. 1, pg 16
CT Loading Factor 1997–1999	0.05	AES assumption
CC Unit Heat Rate (Btu/kWh)	8000	AES assumption
WR Capacity Factor	70.4%	IRP Vol.1, pg 467
CC Capacity Factor	15.0%	
Asset lifetime (years)	20	AES assumption
Fixed O&M in 1992 ($MM)	0.2	IRP p. 456, $.36*180/380*1.031 infl
Var. O&M in 1992 ($MM)	0.3	IRP p. 456 (1.02+0.0147*8000/1000)*1.031*8.76*0.18*capfactor

Allegheny Power System Cost of Capital:

Longterm debt interest rate	9.5%	47.0%	Percent of Required Capital	IRP Vol 1, pg 11
Preferred stock return	9.0%	7.0%	Percent of Required Capital	IRP Vol 1, pg 11
Common stock return	13.3%	46.0%	Percent of Required Capital	IRP Vol 1, pg 11
Weighted Cost of Capital	11.2%			

Avg. Inflation Rate	3.5%	IRP Volume 1, pg 16
Utility Nom. Discount Rate	11.2%	IRP Volume 1, pg 197
AFUDC Rate	11.2%	Estimate based on above Cost of Capital
Weighted corporate income tax rate	38.0%	AES assumption

		Data source: FERC #1 Form 1991 for PE, WPenn, and Monon.
Fuel expense ($MM)	156	Pg 402, Line item #21
Maintenance (1/2)	22.5	Pg 402, Line items #29–33
Total Generation (1e9 kWh)	11.5	Pg 402, Line item #12