STATE OF NEW JERSEY
BOARD OF REGULATORY COMMISSIONERS

DOCKET NO. EM92030359

APPLICATION OF JERSEY CENTRAL POWER & LIGHT COMPANY FOR APPROVAL OF THE POWER PURCHASE AGREEMENT BETWEEN JERSEY CENTRAL POWER & LIGHT COMPANY AND FREEHOLD COGENERATION ASSOCIATES, L.P.	:	NOTICE OF MOTION

PLEASE TAKE NOTICE that Freehold Cogeneration Associates will move, at a time and place to be determined by the Board of Public Utilities, for an Order authorizing Freehold Cogeneration Associates to prefile and to offer in evidence the attached Direct Testimony of Paul L. Chernick and accompanying exhibits.

PLEASE TAKE FURTHER NOTICE that Freehold Cogeneration Associates will rely on the accompanying letter brief in support of this motion.

DATED: November 9, 1994

Respectfully submitted,

SILLS CUMMIS ZUCKERMAN RADIN
TISCHMAN EPSTEIN & GROSS, P.A.

BY: ____________________
JAMES M. HIRSCHHORN

TO: Gerald W. Conway, Esq.
Berlack Israels & Liberman
95 Madison Avenue
Morristown, New Jersey 07960

Elise Goldblatt, DAG
Department of Law & Public Safety
Division of Law
124 Halsey Street
Newark, New Jersey 07102

Gregory Eisenstark, DAG
Department of Law & Public Safety
Division of Law
124 Halsey Street
Newark, New Jersey 07102

Theodore Granger, DRA
Division of Ratepayer Advocate
31 Clinton Street, 11th Floor
Newark, New Jersey 07101

DIRECT TESTIMONY OF PAUL L. CHERNICK

I. INTRODUCTION

Q MR. CHERNICK, BY WHOM ARE YOU EMPLOYED?

A I am the President of Resource Insight, Inc., 18 Tremont Street, Boston Massachusetts, 02108.

Q WILL YOU IDENTIFY EXHIBIT FCA-__A, WHICH IS ATTACHED TO YOUR TESTIMONY AS EXHIBIT A?

A That is my current resume.

Q HAVE YOU TESTIFIED IN ANY ADMINISTRATIVE PROCEEDINGS AS AN EXPERT WITNESS?

A Yes. I have testified approximately one hundred and eighteen times 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 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 Maryland Public Service Commission, the Florida 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 ON EXTERNALITIES?

A Yes. I have testified on externalities valuation and incorporation into utility planning in several jurisdictions, including California, Ontario, Illinois, Massachusetts and Vermont. In addition, I have held advisory assignments regarding externalities with the American Wind Energy Association, the Pace Center for Environmental Legal Studies, and the New York State Energy Research and Development Authority.

Q HAVE YOU AUTHORED ANY PUBLICATIONS ON EXTERNALITIES?

A Yes. I have authored about a dozen publications, listed on my resume, on externalities valuation. I have presented several of these papers at national conferences. I was also one of the principal technical consultants and authors of the Pace University study, *The Environmental Costs of Electricity*.

Q PLEASE DESCRIBE THE WORK OF RESOURCE INSIGHT, INC.

A Resource Insight, Inc. is a research and consulting firm providing professional services in statistics, finance, economics, and assistance with legal and policy analysis.

Q WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A The purpose of this testimony is to present the results of the attached report entitled *A Comparison of External Costs* *of Four Power Plants*, which I coauthored, and to discuss the impact on this analysis of valuing mercury emissions.

II. <u>EXTERNAL ENVIROMENTAL COSTS</u>

Q ARE YOU AWARE OF THE PROPOSAL OF FREEHOLD COGENERATION ASSOCIATES TO CONSTRUCT A 125 MW GAS FIRED COGENERATION POWER PLANT IN FREEHOLD, NEW JERSEY AND SELL 100 MW OF CAPACITY AND ASSOCIATED ENERGY FROM THAT PLANT TO JERSEY CENTRAL POWER AND LIGHT COMPANY?

A Yes. I understand that Freehold Cogeneration Associates proposes to construct such a facility and to sell capacity and energy from it to Jersey Central Power and Light Company under a Power Purchase Agreement approved by the New Jersey Board of Public Utilities in an order dated July 6, 1992.

Q HOW ARE YOU AWARE OF THAT PROPOSAL?

A Freehold Cogeneration Associates engaged Resource Insight, Inc. to prepare a study comparing the air emissions-related externalities associated with the proposed Freehold project to the Keystone and Crown Vista coal-fired independent power production projects, and a generic existing coal-fired power plant.

Q WILL YOU PLEASE IDENTIFY EXHIBIT FCA-__B, WHICH IS ATTACHED TO YOUR TESTIMONY AS EXHIBIT B?

A This is the report Emily Caverhill and I prepared as a result of our analysis, entitled *A Comparison of External Costs of Four Power Plants*.

Q ARE THE FACTS AND CONCLUSIONS STATED THEREIN TRUE TO THE BEST OF YOUR KNOWLEDGE?

A Yes, they are.

Q YOUR REPORT LISTS EMILY CAVERHILL AS CO-AUTHOR. WHO IS MS. CAVERHILL IS AND WHAT WAS HER ROLE IN THE PREPARATION OF THE REPORT?

A Emily Caverhill is an Associate at Resource Insight, and we have worked together on externalities-related topics for five years. She was the principal author of this analysis and report, which was based largely on worked we had previously completed together. While not testifying in the current proceeding, she has testified before public utility commissions five times on the incorporation of externalities in utility planning.

Q WHAT STEPS DID YOU TAKE IN PREPARING THE REPORT?

A We first determined, from New Jersey air emissions permit applications, air emissions of the Freehold, Crown Vista and Keystone projects, and estimated air emissions for a generic existing coal plant. We then compiled several estimates of air pollutant externality values used in utility planning by state public utility commissions, including the New Jersey Board of Public Utilities (BPU). All of the jurisdictions we tabled in the report other than the BPU have adopted explicit dollar values for air emission externalities. For the BPU, which adopted externality costs related to utility supply resources of \$0.02/kWh and \$0.95/MMBtu for electric and gas DSM, respectively, we went to the publication that the Board stated was its source, the so-called "Pace Report," for determining individual air emissions values.[1] Using the BPU's monetary values for the various air emissions and the projected emissions of the four power plants, we determined the implied dollar value of air emissions for each plant, and the difference in externalities between Freehold and each of the others. For comparison, we performed the same analysis using externality values imputed by the New York Public Service Commission and the Massachusetts Department of Public Utilities.

Q PLEASE SUMMARIZE YOUR CONCLUSIONS

A Freehold has the lowest emissions per MWh in five of the six emissions categories compared: sulfur dioxide, nitrous oxides, volatile organic compounds, small particulate matter, and carbon dioxide.

Using air emission values from the Board of Public Utilities' source document and the emissions values as stated, we concluded that the cost per kilowatt-hour of air emissions for each of the four power plants is as follows:

PLANT	COST/KWH
Freehold	$.0071
Keystone	$.0201
Crown Vista	$.0207

[1] Ottinger et al., *Environmental Costs of Electricity*, Pace University Center for Environmental Legal Studies. 1990. Ms. Caverhill and I were co-authors of that study.

Generic Existing Coal $.0572

Assuming that each plant delivered 912,500 MWh annually, the annual cost of air emissions from each plant would be as follows:

PLANT	COST
Freehold	$6,552,573
Keystone	$18,324,841
Crown Vista	$18,922,676
Existing (generic)	$52,151,931

In addition to the pollutants monetized by various regulators, Freehold's mercury benefits are also substantial. Freehold has very low mercury emissions because it would burn mostly natural gas, which contains no mercury, and a small amount of distillate fuel oil, which contains little mercury compared to coal. New Jersey has not adopted a value for mercury emissions. However, if mercury is valued using control costs of $2,500 per pound, the cost of controlling emissions at an MSW plant in Minnesota, these emissions translate into annual costs of roughly $3,600 for Freehold, $110,000 for Keystone, $239,000 for Crown Vista, and $401,500 for the generic coal plant. To the extent that Freehold would displace these or similar projects,[2] it would provide significant mercury benefits to New Jersey and

[2] Residual oil combustion typically has emissions slightly higher than distillate, on the order of 3.2 lbs/10^{12} MMBtu. Office of Air Quality Planning and Standards, *Estimating Air Toxics Emissions From Coal and Oil Combustion Sources*, US EPA 450/2-89-001. April 1989.

surrounding areas. These results are summarized in Figure A attached to this testimony as Exhibit FCA-_G.

Q WHAT IS THE BASIS FOR YOUR USE OF 912,500 MWH ANNUAL PRODUCTION IN THE COMPARISON OF THESE POWER PLANTS?

A While the comparison of the cost per kWh of each plant shows that Freehold has substantial air-emissions benefits relative to the other plants, another comparison was necessary to show the potential annual and lifetime dollar benefits associated with development of the Freehold project. However, the capacity and energy available from these four power plants are not the same. Therefore, capacity and energy estimates for Freehold, the smallest of the three independent projects, were used as the basis for comparison. The figure 912,500 MWh is the product of 125 MW (the capacity of Freehold stayed in its air emissions permit), and 7,300 hours of operation (an 83% capacity factor).

Q WHAT IS THE BASIS OF YOUR USE OF 7300 HOURS OF GENERATION?

A I understand that an analysis of the projected dispatch of the facility, conducted in December 1992, projected 7300 hours of dispatch per year. The environmental costs per kWh may be multiplied by any consistent annual generation to compare alternative technologies.

Q WHAT IS THE PURPOSE OF COMPARING THE KEYSTONE AND CROWN VISTA PLANTS TO THE FREEHOLD PLANT?

A The Keystone and Crown Vista plants are coal-fired generating projects that recently received air emissions permits in New Jersey. They are similar in technology to new coal generating facilities being developed in New Jersey and surrounding states. In addition, I understand that they have power purchase contracts with Jersey Central Power and Light. Therefore, they were chosen to represent new coal-fired generating alternatives to Freehold for the purposes of this comparison.

Q WHAT IS THE PURPOSE OF COMPARING FREEHOLD TO AN EXISTING COAL-FIRED POWER PLANT?

A First, Freehold may be the alternative to life-extension of an existing power plant. Second, for some period of its life, Freehold could cause a reduction in output from an existing power plant. The generic coal facility was chosen to reasonably represent facilities on the existing system that might be displaced by a new gas-fired project such as Freehold. Other existing facilities, including coal-fired boilers with different pollution control measures and oil and gas-fired boilers, could also be displaced a portion of the time and may have different pollutant emissions and environmental costs.

Q WHAT ARE EXTERNAL COSTS?

A In the utility planning context, a cost incurred by the production or consumption of energy is an external cost (or externality) if it is not considered in the decision to produce or consume the energy. For example, air pollutant emissions often cause external costs in the form of human health and welfare effects. Other environmental external costs include impacts on humans and their environment through impacts on water and land. Our report deals strictly with air emissions, since these are the environmental externalities most often valued by utility commissions and the only externalities explicitly valued by the BPU.

Q HOW ARE EXTERNAL COSTS OF AIR EMISSIONS CONSIDERED IN UTILITY PLANNING?

A In the states reviewed for this report, air emissions are assigned dollar values per ton of emissions, which are multiplied by expected emissions from utility resources to estimate resource-specific external costs. Other states and utilities sometimes claim to include environmental costs in a qualitative way, though the effect of qualitative consideration on utility resource selection is often unclear.

The BPU, among several utility commissions, has endorsed the use of monetized externality values for incorporation into utility planning. It explains, in reference to its use of externality values in electric and gas DSM:

> While the Board recognizes that the environmental externality values are imprecise at this time, the

Board believes it is appropriate to include some reasonable value rather than ignore its value as some commenters have suggested. (23 N.J.R. 3376)

(FCA-_D). In this rule, the BPU requires the inclusion of externalities only in the selection of utility DSM. However, the principles and assumptions that underlie the analysis for DSM, including that DSM avoids air emissions from the utility supply system and reducing these emissions is valuable, also may apply to other utility resource and operations decisions.

Q WHY IS IT DESIRABLE TO INCLUDE EXTERNAL COSTS OF AIR EMISSIONS IN UTILITY RESOURCE PLANNING?

A Virtually all utility resource decisions involve trade-offs between direct costs, such as for fuel, construction and labor, and non-price factors. Non-price factors include such things as fuel diversity, system reliability, and environmental quality. Some of these non-price factors are incorporated in utility planning as constraints, such as system reliability, while others require a trade-off analysis that balances sometimes uncertain utility costs with social costs. Whether explicitly valued or not, external costs are imputed value in utility resource planning through the selection of resources that have measureable costs and environmental attributes. Incorporating estimates of external costs of air emissions formalizes the incorporation of air emissions into utility planning. Using external costs for air emissions encourages consistent treatment of the air-related impacts of competing resources. External costs are relatively easily incorporated into the calculations of resource costs and utility avoided costs for use in resource selection, as demonstrated by the BPU in its regulation governing the selection of DSM.

Q HOW DOES THE NEW JERSEY BOARD OF PUBLIC UTILITIES VALUE THE AIR EMISSION EXTERNAL COSTS OF FOSSIL FUEL GENERATION?

A In the regulations governing utility demand side management programs, N.J.A.C. 14:12-3.8(a) requires that environmental externalities be explicitly reflected in utility net benefits calculations, avoided cost savings studies, standard offer pricing, competitive offer pricing, and comparison of total resource costs. N.J.A.C. 14:12.3.8(b) fixes the blended environmental externality cost for all utility generation at an average of 2¢/kWh in 1991 dollars, to be adjusted annually at the rate of the GNP deflator.

Q HOW DID THE BOARD DERIVE THIS FIGURE?

A The Board apparently relied upon a report prepared by Pace University for the New York State Energy Research and Development Authority and the U.S. Department of Energy, Ottinger, et al., *Environmental Costs of Electricity*, Oceana Press 1990 (the "Pace Report"). In its Notice of Proposed Rulemaking, 23 N.J.R. 1286 (May 6, 1991), the Board summarized the Pace Report's conclusions as to specific environmental costs per kWh for different classes of generating plant, including coal fired plants meeting new source performance standards and natural gas fired combined cycle plants. (Exhibit FCA-__C) The Board averaged these values, adjusted for the time diffentiated mix of generating plant, to develop the 2¢/kWh environmental cost of all fossil fuel generation in the DSM regulations. See Response to Public Comments, 23 N.J.R. 3375-76 (November 4, 1991). (Exhibit FCA-__D)

The Board also noted that the environmental costs adopted by the Massachusetts Department of Public Utilities and the Nevada Public Service Commission "closely follow the figures established in the Pace Report." Those environmental costs are cited in Table 2 of our report.

Q DOES THE PACE REPORT ESTIMATE ENVIRONMENTAL COSTS FOR SPECIFIC TYPES OF EMISSIONS?

A Yes. It estimates specific costs per ton for sulfur dioxide, nitrous oxides, carbon dioxide, and particulate matter. The Pace Report's findings with respect to these costs are attached to my testimony as Exhibit FCA-__E. Exhibit FCA-__F is an excerpt from the Pace Report explaining my and Ms. Caverhill's involvement in the development of the air emission externality values, specifically, and other aspects of the Pace Report, in general.

Q HOW DID THE PACE REPORT ESTIMATE ENVIRONMENTAL COST PER KWH FOR VARIOUS TYPES OF GENERATING PLANT?

A The Pace report generally used a damage-cost approach to estimate externality values in dollars per ton of pollution for varios pollutants. For a CO_2 externality value, in the absence of global warming damage estimates, the Pace Report used mitigation cost estimates. The Pace Report also estimates emissions of these pollutants per kWh generated for each type of generating plant. By applying the cost per ton to these emissions, it derives its emissions-related environmental cost per kWh for each type of generating plant.

Q HOW DID YOU ESTIMATE THE COSTS PER KWH FOR THE FREEHOLD, KEYSTONE AND CROWN VISTA PLANTS CITED IN YOUR TESTIMONY AND REPORT?

A We applied the methodology and underlying findings of the Pace Report to emissions data for the specific plants. Specifically, we used the Pace Report's values for the cost of each type of emission per ton. Instead of using classes of generating plants, as the Pace Report did, we applied these values to the permitted emission levels of the specific plants. We also applied them to estimates of the emission levels of the generic coal plant.

Q HOW DID YOU ESTIMATE THE COSTS PER KWH FOR THE GENERIC COAL PLANT CITED IN YOUR TESTIMONY AND REPORT?

A We used the Pace Report's values for each type of emission. Emission volumes were derived from a variety of sources. SO_2 emissions reflect federal Clean Air Act compliance levels for coal plants beginning in year 2000[3]; this is somewhat lower than present emission levels at some plants. NO_x emissions reflect Northeast States for Coordinated Air Use Management compliance levels for wet-bottom boilers.[4] Particulate matter emissions were estimated from U.S. Environmental Protection Administration *sources*.[5] CO_2 emissions were estimated based on typical carbon contents and heating values of eastern coals.[6]

Q WHAT IS THE BENEFIT OF THIS ANALYSIS?

A Using underlying costs for specific emissions from a source deemed reliable by the Board, it allows the Board to compare the environmental external costs of specific generating plants in evaluating the economic consequences of building or dispatching those plants.

III. <u>EXTERNAL COSTS OF MERCURY EMISSIONS.</u>

Q PLEASE SUMMARIZE THE EFFECTS OF MERCURY ON HUMAN HEALTH AND THE ENVIRONMENT.

---

[3] U.S. Environmental Protection Administration, *Clean Air Act Amendments of 1990 Detailed Summary of Titles*, November 30, 1990, Capter IV, page 4.

[4] *NESCAUM Stationary Source Committee Reocmmendation on NO_x RACT for Utility Boilers* (March 25, 1992).

[5] U.S. Environmental Protection Administration, *Compilation of Air Pollutant Emission Factors*, Vol. I: Stationary Point and Area Sources, AP-42 (4th ed. 1985).

[6] For example, Fink and Beatty (1978) list a Virginia coal with 14,030 Btu/lb. and 80.1% carbon (57.1 lb. C/MMBtu) and a Pennsylvania coal with 13,610 Btu/lb and 76.6% carbon (56.3 lb. C/MMBtu). A carbon content of 57 lb. C/MMBtu is equivalent to emissions of 209 lb. CO_2/MMBtu. [57 x 44/12 = 209 (the ratio of the molecular weight of carbon dioxide to carbon is 44:12)].

A According to the US Public Health Service,[7] long term exposure to either organic or inorganic mercury can cause permanent damage to the brain, kidneys and developing fetuses. Effects include tremors, memory loss, and kidney desease. Short-term exposure to high levels of mercury cause similar types of effects, but are sometimes reversible. Pathways of exposure include ingestion of mercury-containing food, such as many types of fresh- and saltwater fish and grain, consumption of contaminated water, and inhalation of metallic mercury.

Wildlife most at risk include species higher on the food chain that consume large quantities of fish, such as loons, eagles, otter, mink, kingfisher, and osprey. Potentially important effects include reproductive impairment and central nervous system effects in predators.[8]

Because of the persistent nature of mercury in the environment, mercury emissions may remain benign for a period but be eventually concentrated, contributing to elevated levels in fish and grain and a threat to humans and their environment.

---

[7]Clement Associates, *Toxicological Profile for Mercury*, Agency for Toxic Substances and Disease Registry, US Public Health Service with US EPA, December 1989.

[8]Swain, Edward B. (Ed.), *Strategies for Reducing Mercury in Minnesota*, MPCA Mercury Task Force, Minnesota Pollution Control Agency, St. Paul Minnesota. 1994

Q HAS ANY PUC VALUED MERCURY EMISSIONS FOR UTILITY PLANNING, EITHER AS A UTILITY COST OR AN EXTERNALITY?

A No PUC, to our knowledge, has determined an externality value for mercury nor yet required the inclusion of specific mercury control costs in utility planning. However, concern about mercury emissions is rising as evidenced by health advisories in many states concerning mercury contamination of freshwater fish. In addition, the Clean Air Act Amendments of 1990 require additional pollution controls on industrial sources of mercury emissions and other toxics, and required studies and potentially controls on utility resources that emit mercury.

Q HOW MIGHT MERCURY CONTROL REQUIREMENTS AFFECT UTILITY COSTS?

A Utility resources affected by mercury control requirements would see increased costs for mercury emissions reductions. For existing utility coal plants, control measures are likely to include carbon injection, which would have increased capital and operating costs associated with it. These costs would increase the cost of continuing to use existing coal resources.

For coal-fired non-utility generators that are required to install mercury controls, there will also be an increase in capital and operating costs. Depending on the terms of the power sales contract, these costs could be borne directly by the purchasing utility or could be absorbed by the developer. In the latter case, while the utility would not, theoretically, experience an increase in cost as a result of the mercury controls, the additional cost might affect the financial health of the developer and of the project.

One promising control method for coal and MSW power plants is carbon injection. The Minnesota Pollution Control Agency estimated that mercury controls on the Hennepin MSW facility would cost $2,500-$3,500 per pound of mercury controlled.[9] The EPA estimated that the cost of this technology would be on the order of $950 per pound mercury for smaller plants.[10]

Q HOW WOULD VALUATION OF MERCURY AFFECT THE ENVIRONMENTAL COSTS AND BENEFITS OF THE FREEHOLD COGENERATION PROJECT?

A Due to its predominant use of natural gas, Freehold has very low mercury emissions. Valued at $2,500 per pound, mercury emissions would add roughly $3,600 per year to the environmental cost of Freehold. (See Figure A attached.) In contrast, annual mercury emissions from Keystone are worth approximately $110,000, Crown Vista $239,000, and the generic existing coal plant $401,500.

---

[9] Swain, Edward B. (Ed.), *Strategies for Reducing Mercury in Minnesota*, Minnesota Pollution Control Agency Mercury Task Force, St. Paul, Minnesota. 1994

[10] US EPA, *Economic Impact Analysis for Proposed Emission Standards and Guidelines for Municipal Waste Combustors*, EPA-450/3-91-029. March 1994

The mercury benefits of developing Freehold would depend on the utility resources avoided. However, if existing coal of the type specified was avoided the annual benefit would be on the order of $398,000. Over a twenty year contract period, assuming a five percent real discount rate this environmental benefit would be approximately $5 million.

Q HOW DID YOU DERIVE THE MERCURY EMISSIONS USED IN YOUR ANALYSIS?

A For Keystone and Crown Vista we used the maximum emissions levels for mercury (in pounds per hour) permitted by the state and the maximum plant output (in hours) as reported in the air quality permits. Other mercury emissions are from the EPA.[11]

Q DOES THIS CONCLUDE YOUR TESTIMONY?

A Yes.

---

[11] US EPA Office for Air Quality Planning and Standards, *Estimating Air Toxics Emissions from Coal and Oil Combustion Sources*, EPA-450/2-89-001, Research Triangle Park, North Carolina. April 1989.

EXHIBIT A

RECYCLED

EXHIBIT B

RECYCLED

Resource Insight, Inc.

A Comparison of External Costs of Four Power Plants

Prepared for Constellation Energy, Inc.

by Emily Caverhill
and Paul L. Chernick

October 1994

18 Tremont Street, Suite 1000
Boston, Massachusetts 02108

Executive Summary

It is becoming common for regulatory bodies to assess the external impacts of proposed electric supply resources by assigning a monetary measure to the quantity of pollutants emitted. This report briefly explains what external costs are and why they are relevant to the selection of new electricity supply resources. The externality values used in utility resource planning in several states are presented, with a brief discussion of the externality values used in demand-side management resource planning in New Jersey. The principles of externality valuation are then applied to compare the air emissions and external costs of the Freehold Cogeneration Facility with three coal-fired electric utility supply resources.

The proposed Freehold Cogeneration Facility is a 125 MW gas-fired combined cycle cogeneration plant fitted with a dry low-NOx burner and water injection for pollution control. It is permitted to use No. 2 oil as a back-up fuel for a maximum of 480 hours per year. The plant meets or exceeds emissions criteria for gas-fired facilities under the Clean Air Act, and would be located in Freehold Township in New Jersey. In this report, Freehold is compared to the Keystone Cogeneration Systems project and the Crown/Vista Energy Project, pulverized coal-fired boilers currently being developed in New Jersey, and a generic coal plant typical of plants operating in the PJM power pool.

This external cost analysis was conducted to compare the air emissions and external costs of Freehold to its coal-fired counterparts. The comparison was limited to air emissions valued by the public utility commissions in New Jersey, Massachusetts and New York, which are: sulfur dioxide (SO2), nitrogen oxides (NOx), volatile organic compounds (VOCs), small particulate matter (PM10), carbon monoxide (CO), and carbon dioxide (CO2). The values used in these states were also used in the comparison of externalities. Massachusetts on the high end and New York on the low end roughly bracket the externality values used in utility planning for areas comparably situated to New Jersey, while New Jersey falls in between.[1] Emissions values were based on permitted emissions limits for the new facilities and generic emissions factors for the existing coal plant.

[1] See Table 2 for a summary of externality values. Comparable areas include those with moderate to serious ozone levels and no or few violations of ambient air quality limits for the other criteria pollutants SO2, NOx, PM10, and CO. For the greenhouse gas CO2, all values could be considered comparable, in which case the high value of $22/ton from Massachusetts is roughly half the $40/ton high value used in utility planning by Oregon.

Our results show that on a pounds-per-megawatt-hour basis, Freehold has the lowest emissions of five of the six emissions compared, including SO2, NOx, PM10, CO and CO2. For SO2 and NOx, Freehold's emissions are an order of magnitude less than those of Keystone and Crown Vista, and two orders of magnitude less than those of an existing coal plant. For PM10, Freehold's emissions are roughly half those of Keystone and Crown Vista, and one-seventh those of the existing coal plant. For CO2, Freehold's emissions are roughly half those of Keystone, Crown Vista, and the existing coal plant.

Based on New Jersey's valuation of air emissions, Freehold has approximately one-third the external costs of Keystone and Crown Vista and one-eighth the external costs of an existing coal plant.[2] Compared on the basis of annual generation of 912,500 MWh, Freehold has external costs of $6,522,573, Keystone has $18,324,841, Crown Vista has $18,922,678, and existing coal has $52,151,931. During periods when if operated, Freehold would displace generation from these or similar resources, annual air externality benefits on the order of $11.8 million to $45.6 million dollars would accrue. Comparison using externality values from Massachusetts and New York for air emissions also show substantial benefits.

Lifetime net air externality benefits of operating Freehold depend on the resources that would be operated in its absence. However, assuming that the development of Freehold resulted in comparable reduction in generation from an existing coal plant, a twenty year contract period and a 5% real discount rate, these benefits would be on the order of $613 million dollars (present value).

What Are External Costs?

In the utility planning context, a cost incurred by the production or consumption of energy is an external cost (or externality) if it is not considered in the decision to produce or consume the energy.[3] Electric utilities impose environmental costs on society that are not incorporated into resource decisions.

---

[2] Fractions were calculated based on the cost per MWh of generation from each plant.

[3] Portions of this report were taken from Paul L. Chernick and Emily Caverhill, "Externalities," Chapter 3 of *From Here to Efficiency,* Volume 5, prepared for the Pennsylvania Energy Office, January 1993. A lengthier discussion of how this definition fits into economic theory is presented there.

Most costs related to the impact of air emissions on humans and their environment from utility resources are external costs.[4] External costs caused by air emissions can include monetary costs related to human health care, worker productivity, damages to crops, forests, fisheries and materials, reduced recreation and tourism, and compliance with regional air quality goals. Non-monetary costs can include reduced welfare in the forms of pain and suffering, the aesthetic cost of visibility reduction, lost quality of recreational opportunities, and the existence value of species and ecosystems.

Electricity production may also cause other external costs or benefits related to other environmental, economic, or social impacts. These impacts are often at least partially included in markets for land, water, fuel and wages. Limited data is available on the external portion of these costs. With few exceptions, these other external costs have not been valued for utility planning.

External Costs and Utility Planning

Virtually all utility resource decisions involve trade-offs between direct costs, such as costs for fuel, construction and labor, and non-price factors. Non-price factors traditionally considered in utility resource planning include fuel diversity and system reliability. More recently, other non-price factors are also being considered in utility resource planning, including more emphasis on risk and environmental costs (or benefits) of competing resources. The practice of placing a dollar value on such non-price factors as environmental impacts is a relatively new tool for regulators to use to fulfill their traditional role of minimizing ratepayer costs while considering important non-price factors.

In the selection of new resources, valuing external costs allows utilities to select resources with the least total social costs. Using this method, utility resources are compared and selected based on their combined direct and external costs, rather than their direct costs alone.

Similarly, external costs could be used to make decisions about power plant-dispatch (by selecting resources in the order of least social cost), fuel choices (by

---

[4] Prior to 1990, virtually all air emissions were external to the utility planning process. However, the Clean Air Act of 1990 established a national emissions-allowance program for SO2 and offset provisions for new sources of ozone precursors, each of which may internalize a portion of the costs related to SO2 and NOx emissions. The externality values discussed in this report generally reflect costs not internalized, however, in the future, some of these costs may become utility costs and cease to be externalities.

comparing the least-polluting fuel's cost with its external benefits), and pollution control (by determining the cost-effectiveness of pollution-control equipment or other mitigation measures). To date, regulators have used external costs primarily to help make decisions about selecting new resources, not decisions about running existing resources. However, measures such as lower-sulfur fuel, controls on existing power plants, and intelligent dispatching of existing power plants are often effective ways of reducing the overall social costs of generating electricity.

Whether used for selection of new resources or throughout utility operations, external costs reflect real costs of utility resources. As the New Jersey Board of Public Utilities states:

> The values included for environmental externalities reflect legitimate benefits that accrue to all ratepayers. (23 N.J.R. 3375)

Some critics of the use of external costs contend that external impacts cannot be expressed in dollar terms. However, this is not the New Jersey Board's position. With regard to electric and gas utility demand-side management, it states:

> While the Board recognizes that the environmental externality values are imprecise at this time, the Board believes it is appropriate to include some reasonable value rather than to ignore its value as some commenters have suggested. (23 N.J.R. 3376)

External impacts are present in resource planning whether or not valuation is attempted using an externality valuation technique. If a utility uses only its direct costs to select new resources, it values external impacts at zero. If it considers external impacts on a qualitative basis, but does not change its resource plan as a result of this consideration, then it has valued external impacts at less than the cost of changing its resource plan. If it considers external impacts on a qualitative basis and changes its resource plan, then it has valued external impacts at more than the cost of changing its resource plan. Valuing external impacts independently of the resource-planning process provides a consistent measure of the value of specific environmental factors. This measure of consistency, within a utility and across utilities within the state as appropriate, is a powerful tool for utility regulators to determine when utility resources are truly cost-effective from society's perspective.

In addition, clear policies that value cleaner resources provide signals to utilities and others that encourage innovation and reduction in total energy-resource costs. Dollar values for external impacts inform interested parties (vendors, contractors, developers, utility staffs) of the desired trade-off between direct and external costs, allowing for focused efforts to develop more desirable resources. Less quantitative methods of reflecting external impacts cannot provide as clear a signal to promote desirable innovations.

How Does New Jersey Value External Environmental Impacts?

New Jersey values external environmental impacts in the evaluation of electric utility and gas utility DSM. The rule states:

> 14:12-3.8 Environmental Externalities
>
> (a) The avoided societal cost of environmental impacts related to construction and operation of electric and natural gas supply projects and electric and natural gas consumption, hereinafter referred to as environmental externalities, shall be explicitly reflected in net benefits calculation, avoided cost savings studies, standard offer pricing, competitive offer pricing and the TRC test.
>
> 1. For the initial DSM plan filing and until otherwise modified by the Board, the following environmental externality values shall apply:
>
> i. For electric utility DSM Programs, the environmental externality value shall be \$.02 per kilowatt-hour (kWh). The electric environmental externalities shall be time differentiated consistent with time differentiation of avoided cost schedules in order to reflect the changing mix of generation sources during different time periods. Nonetheless, the average value shall be \$.02 per kWh.
>
> ii. For gas utility DSM Programs the environmental externality value shall be \$.95 per one million British thermal units (MMBtu).
>
> iii. The environmental externalities provided for herein are in 1991 dollars. These values shall be adjusted annually at a rate equal to the GNP deflator index. (23 N.J.R.3383)

These values for electric and gas DSM were derived from damage-based externality values for four air emissions (SO2, NOx, CO2 and particulates) developed in a report prepared by Pace University for the New York State Energy Research and Development Authority and the U.S. Department of Energy,[5] and assumptions regarding the marginal fossil resources avoided by DSM. (23 N.J.R. 3376)

The Board clearly acknowledged the differences in the external costs of fossil generation resources in selecting these externality values for DSM. It states:

[5] The report is Ottinger, et al., *Environmental Costs of Electricity*, Oceana Press 1990.

Making the conservative assumption that all coal-fired units from which New Jersey utilities purchase electricity meet the New Source Performance Standards (NSPS) established by the N.J. Department of Environmental Protection and Energy, (which will not be the case for a number of years), and employing a weighted average of New Jersey electric fuel mix (including purchases of 50 percent coal, 10 percent gas, and 10 percent oil), electric generation produces an average air pollution environmental cost of 2.65 cents per kWh. This assumes no environmental cost for nuclear generation. The predominant marginal generating technologies appearing in the New Jersey utilities' capacity plans are natural gas-fired combustion turbines or combined cycle units. The Pace Report estimates that the environmental cost of generation from the avoided production plant is more on the order of 1.0 cent per kWh. However, the avoided gas-fired combustion turbine or combined cycle facility would be expected to run from several hundred to several thousand hours per year predominantly during peak and shoulder periods. As a result, baseload energy efficiency DSM measures can be expected to avoid generation from existing plant, likely coal-fired facilities, during off-peak hours.

In consideration of the factors noted, the proposed rules establish an average value for electric environmental externalities of 2.0 cents per kWh....

For natural gas, the value for environmental externalities is established in the rule at $.95/MMBtu (one million British thermal units), which approximates the environmental costs established in the Pace report for natural gas combustion at an electric generating facility. As with the electric figures, this value is considered conservative since the gas-fired electric generating unit is assumed to have various emission controls not present at natural gas end user premises. (23 N.J.R. 3376)

The Board does not currently require an external cost analysis for resource decisions other than DSM. However, technically speaking, the principles and assumptions that underlie the analysis for DSM, including that air emissions are costly and reducing them is valuable, also apply to the air emissions of other fossil utility resources.

What Other Jurisdictions Require Consideration of External Costs?

State externality regulations vary in their treatment of environmental impacts and the financial risk associated with future environmental regulations. Externality orders in California, Massachusetts, Montana and Oregon consider both environmental impacts caused by air emissions and environmental compliance cost risk.[6] Arizona, Hawaii, Minnesota, Nevada, New York, New Jersey, Vermont and the Bonneville Power Association appear to be primarily concerned with environmental impacts. These states do not explicitly address compliance risk in their regulations governing externalities, though these costs may be included elsewhere in their regulations. Wisconsin, Missouri and Utah focus on financial risk. Other states may require qualitative consideration of externalities.

Of the states mentioned above, several have developed explicit externality values for air emissions for use in utility planning. These values, along with values for land and water impacts adopted by New York and the Bonneville Power Administration, are summarized in Table 2.

Several states have relied on control costs for valuing environmental impacts, including California,[7] Massachusetts, Minnesota, Nevada, New York, Oregon, and Wisconsin. Control-cost based externality values for air emissions are estimates of society's willingness to pay for small reductions in air emissions. Willingness to pay for emissions reductions is estimated by examining the decisions of environmental regulators regarding appropriate control measures for meeting air quality goals. Since environmental regulators consider the costs of control measures in their decisions to require them, externality estimates are based on the costs of controls required by regulators when available. Consistent with marginal cost theory, it is the marginal cost of control that is relevant for estimating willingness to pay for emissions reductions, and this is the basis of most control-cost based externality values.

Other jurisdictions, including California, New Jersey and the Bonneville Power Administration, rely on estimates of damages. Damage-based estimates are based on a compilation of the damages associated with known effects of a pollutant. Typically, a damage assessment brings together many disciplines as diverse as climatology, epidemiology and oncology to determine what damages occur, and then an environmental economist estimates the value of those damages. For some effects, such as crop loss or materials damages, values are largely determined in the marketplace, but for others, such as premature death or disability, valuation is more difficult. Poor data (e.g. for climate change), low probability and high cost events (e.g. nuclear accident), chronic exposure effects, synergistic effects among

---

[6] Oregon's use of control costs appears to combine implied valuation and financial risk, though this is not explicitly stated in its externality Order.

[7] California's previous externality values were based on control costs. The current values, shown in Table 2, are based on damage costs.

pollutants, and inter-generational effects all complicate damage valuation.[8] Nonetheless, damage valuation is the preferred method stated by several utility regulators.

How Does the Freehold Cogeneration Project Compare to Other Power Plants?

Tables 1-6 present air emissions and calculate resulting external costs for the Freehold project compared with Keystone, Crown Vista and a generic coal plant. Table 1 shows emissions in pounds per million Btu and pounds per megawatt-hour for these plants. Table 2 summarizes the externality values adopted by state or regional utility regulators, including New Jersey. Table 3 calculates external costs based on New Jersey externality values. Tables 4 and 5 calculate external costs based on Massachusetts and New York PSC externality values, respectively. Table 6 combines the results in Tables 3-5.

Since the New Jersey Board of Public Utilities has adopted externalities for some utility planning practices, their estimates were used in comparing power plant external costs. In addition, the analysis used externality values from New York and Massachusetts for comparison. Like New Jersey, these states are members of the Northeast Transport Region for the purposes of Federal ambient ozone level compliance and encompass non-attainment areas for ozone. Also these states have few or no violations of ambient air levels for the other criteria pollutants. Massachusetts' externality values are based on marginal control costs for emissions of criteria pollutants in Massachusetts, and national mitigation costs for CO_2. Marginal control costs for the criteria pollutant emissions may be similar in New Jersey. Externality values adopted by the New York PSC represent the low end of the range of values presented in Table 2. New York, the first state to adopt externality values in 1989, adopted externality values that were based on average, not marginal control costs. Based on data in the New York State Energy Plan,[9] these costs are generally substantially below marginal control costs in New York.

Together, these tables show that on a pounds-per-megawatt-hour basis, Freehold has the lowest emissions of five of the six emissions compared, including SO_2, NOx, PM10, CO and CO_2. For SO_2 and NOx, Freehold's emissions are an order of magnitude less than those of Keystone and Crown Vista, and two orders of

---

[8] The use of control costs does not avoid these issues, it leaves them up to environmental regulators, who grapple with them in setting regulations.

[9] New York State Energy Plan 1992.

magnitude less than those of an existing coal plant. For PM10, Freehold's emissions are roughly half those of Keystone and Crown Vista, and one-seventh those of the existing coal plant. For CO2, Freehold's emissions are roughly half those of Keystone, Crown Vista, and the existing coal plant.

Based on New Jersey's valuation of air emissions, Freehold has approximately one-third the external costs of Keystone and Crown Vista and one-eighth the external costs of an existing coal plant.[10] Compared on the basis of annual generation of 912,500 MWh, Freehold has external costs of $6,522,573, Keystone has $18,324,841, Crown Vista has $18,922,678, and existing coal has $52,151,931. During periods when if operated, Freehold would displace generation from these or similar resources, annual air externality benefits on the order of $11.8 million to $45.6 million dollars would accrue.

Results from the use of externality values from Massachusetts and New York for air emissions also show substantial benefits. Using Massachusetts externality values, Freehold's relative annual benefits would be $19.9 million to $66.2 million. Using New York PSC values, Freehold's relative annual benefits would be $2.8 million to $17.6 million.

Lifetime net air externality benefits of operating Freehold depend on the resources that would be operated in its absence. However, assuming that the development of Freehold resulted in comparable reduction in generation from the existing coal plant, a twenty year contract period, a 5% real discount rate, and New Jersey externality values, these benefits would be on the order of $613 million dollars (present value).

[10] Fractions were calculated based on the cost per MWh of generation from each plant.

Table 1: Power Plant Stack Emission Factors

	lbs/MMBtu			
Pollutant	*Freehold*	*Keystone [b]*	*Crown Vista [c]*	*Existing Coal [d]*
SO_2	0.0119	0.1600	0.1800	1.2000
NOx	0.0199	0.1700	0.1700	1.0000
VOCs	0.0069	0.0036	0.0031	0.0027
PM10	0.0090	0.0180	0.0180	0.0673
CO	0.0196	0.1100	0.1100	0.0231
CO_2 [h]	112.9143	209.0000	209.0000	209.0000
	lbs/MWh			
	Freehold	*Keystone*	*Crown Vista*	*Existing Coal*
SO_2	0.1	1.5	1.8	13.2
NOx	0.2	1.6	1.7	11.0
VOCs	0.1	0.0	0.0	0.0
PM10	0.1	0.2	0.2	0.7
CO	0.2	1.1	1.1	0.3
CO_2 [h]	902.4	2015.4	2037.8	2299.0

Notes:

lbs/MWh = (lbs/MMBtu) x heat rate. The heat rates, (in MMBtu/MWh) are as follows:

Freehold	*Keystone*	*Crown Vista*	*Existing Coal*
7.992	9.643	9.750	11.000

Source: Freehold Cogeneration Association

[a] For all pollutants except CO_2, emission rates are a weighted average of natural gas and distillate oil emissions, based on maximum hours of operation (8400 total, 480 burning oil). Data are from Attachment 1 to Freehold's "permit to construct, install, or alter control apparatus or equipment and temporary certificate to operate control apparatus or equipment," Tables 1 and 2.

[b] For all pollutants except CO_2, emission rate data are from Attachment-I to Keystone's "permit to construct, install, or alter control apparatus or equipment and temporary certificate to operate control apparatus or equipment and prevention of significant deterioration permit," (September 6, 1991) Table 1. After five years of operation, the permitted NOx emission rate will be revised to between 0.10 and 0.17 lbs/MMBtu, depending on performance.

[c] For all pollutants except CO_2, emission rate data are from Attachment-I to Crown Vista's "permit to construct, install, or alter control apparatus or equipment and temporary certificate to operate control apparatus or equipment and prevention of significant deterioration permit," (Log no. 01-92-0857; October 1, 1993) Table 1. After two years of operation, the permitted NOx emission rate will be revised to between 0.10 and 0.17 lbs/MMBtu, depending on performance.

[d] Emissions factors from EPA AP-42, assuming a wet-bottom pulverized-coal-fired boiler, with ESP (95% efficiency). NOx emissions reflect NESCAUM Phase I RACT compliance levels; compliance levels for other boilers and for phase II, scheduled for implementation in 1999, may be lower.

[h] Based on generic heat content. The actual values may vary, especially for coal.

Table 2: Externality Values by Jurisdiction
(Various-years' dollars per ton)

	Pollutants						Greenhouse Gasses			Other (¢/kWh)	
	SO_2	NOx	VOCs	Particulates[o]	CO	Air toxics	CO_2	CH_4	N_2O	Water use	Land use
Cal. Energy Commission[a]											
South Coast[b]	7,425	14,488	406	47,620	3	.	7.64	.	.	.	.
Bay Area[c]	3,482	7,345	90	24,398	1	.	7.64	.	.	.	.
San Diego[c]	2,676	5,559	98	14,228	1	.	7.64	.	.	.	.
San Joaquim Valley[c]	1,500	6,473	3,711	3,762	0	.	7.64	.	.	.	.
Sacramento Valley[c]	1,500	6,089	4.129	2,178	0	.	7.64	.	.	.	.
North Coast[c]	1,500	791	467	551	0	.	7.64	.	.	.	.
North Central Coast[c]	1,500	1,959	803	2,867	0	.	7.64	.	.	.	.
South Central Coast[c]	1,500	1,647	286	4,108	0	.	7.64	.	.	.	.
Southeast Desert[c]	1,500	439	157	715	0	.	7.64	.	.	.	.
Out-of-state NW[d]	1,500	730	0	1,280	.	.	7.64	.	.	.	.
Out-of-state SW[d]	1,500	760	5	1,280	.	.	7.64	.	.	.	.
Cal. PUC[e]											
SCE and SDG&E	19,717	26,397	18,855	5,710	.	.	7.64	.	.	.	.
PG&E	4,374	1,904	3,556	2,564	.	.	7.64	.	.	.	.
Massachusetts DPU[f]	1,700	7,200	5,900	4,400	960	.	24.00	240	4,400	.	.
Minn. PUC (interim)[g]	1,500	760	5	1,280	.	.	7.64	.	.	.	.
Nevada PSC[h]	1,560	6,800	1,180	4,180	920	.	22.00	220	4,140	*SS*[p]	*SS*[p]
New Jersey BPU[i]	4,060	1,640	.	2,380	.	.	13.60	.	.		
New York PSC[j]	832	1,832	.	333	.	.	1.10	.	.	0.10	0.40
New York SEO[k]	921	4,510	3,188	2,645	307	75,490	6.20	.	.	.	.
Oregon PSC[l]											
Low	.	2,000	.	2,000	.	.	10.00	.	.	.	.
High	.	5,000	.	4,000	.	.	40.00	.	.	.	.
Wisconsin PSC[m]	.	.	.	.	.	.	15.00	150	2,700	.	.
BPA[n]	.	.	.	.	.	.	.	.	.	.	
West	1,500	884	.	1,539	.	.	.	.	.	.	0–0.20
East	1,500	69	.	167	.	.	.	.	.	.	0–0.20

EXTSTATE.XLS as of 8/94

Table 2: Externality Values by Jurisdiction (Various-years' dollars per ton)

Notes

[a] California Energy Commission Electricity Report, Tables 4-1 and 4-2, November 1992. 1989 dollars.

[b] Includes Ventura County.

[c] Values for resources located inside California.

[d] Values for resources located outside California.

[e] California PUC values from California Energy Commission Staff, "In-State Criteria Pollutant Emission Reduction Values" (Testimony), November 19, 1991, Table 2. 1989 dollars.

[f] Massachusetts DPU Decision in Docket 91-131, November 10, 1992. 1992 dollars.

[g] Minnesota PUC Decision in Docket No. E-999/CI-93-583, March 1, 1994. 1994 dollars.

[h] Nevada PSC Decision in Docket No. 89-752, January 22, 1991. NOx and VOC values are only for areas that comply with federal ambient ozone standards, as all areas in Nevada currently do. The Nevada PSC says its NOx values for areas that do not comply is "equal to or greater than" those listed, and that its VOC value is for such areas is $5,500/ton. 1990 dollars.

[i] Values adopted by the NJBPU were $0.02/kWh for electric utility DSM programs and $0.95/MMBtu for gas utility DSM. (23 NJR 3383) The pollutant values shown here reflect the BPU's reasoning outlined in 23 NJR 3376 response to Comment 134 and the "Pace Report" to which it refers (Ottinger 1990). 1991 dollars.

[j] NYPSC, "Consideration of Environmental Externali ties in New York State Utilities Bidding Programs, 1989. Values: 0.25 ¢/kWh for SO_2, 0.55 ¢/kWh fo NOx, 0.1 ¢/kWh for CO_2, 0.005 for TSP, 0.1 ¢/kW for water discharge, and 0.4 ¢/kWh for land us impacts for a total of 1.405 ¢/kWh total for a NSP coal plant. Values are translated to $/ton by Sur Putta, "Weighing Externalities in New York State, *The Electricity Journal,* July 1990. 1989 dollars.

[k] NYSEO, 1994 Draft New York State Energy Plan Volume III: Supply Assessments, February 1994, p 529. Values shown represent "mid-range" values. Fo utility planning, NYSEO estimated low as 50% o mid-range values and high values as 200% of mid range values. 1992 dollars.

[l] Oregon PUC Order No. 93-695, May 17, 1993, p. 5 1993 dollars.

[m] Wisconsin PSC Order in Docket No. 05-EP-6 September 18, 1992, p. 95. 1992 dollars.

[n] Bonneville Power Administration, "Application o Environmental Cost Adjustments During Resourc Cost Effectiveness Determinations," May 15, 1991 "Land and other" values vary from 0 for DSM to 0. ¢/kWh for coal and new hydro. SO_2 value is zero i offsets are purchased. 1990 dollars.

[o] Values for California and Minnesota are per ton o particulate matter smaller than 10 microns (PM10) all other values are per ton of total suspende particulates (TSP).

[p] Site specific.

Table 3: Externalities of Air Emissions based on New Jersey BPU Externality Valuation for DSM

Pollutant	NJ BPU Ext Value (1994$) [a]	cents/kWh [b] Freehold	Keystone	Crown Vista	Existing Coal
SO2	2.22	0.02	0.34	0.39	2.93
NOx	0.90	0.01	0.15	0.15	0.99
PM10	1.30	0.01	0.02	0.02	0.10
CO2	0.01	0.67	1.50	1.51	1.71
Total cents/kWh		0.71	2.01	2.07	5.72
Total $/year [c]		6,522,573	18,324,841	18,922,678	52,151,931

Notes:

[a]: State externality values as explained in Table 2, expressed in 1994$/lb.

[b]: Cents/ kWh calculated as [emissions (lbs/MWh) from Table 1] × [a].

[c]: For comparison, total $/year is the product of total cent/kWh values and annual generation of 912500 MWh, the annual operation of the 125 MW Freehold Cogeneration Project for 7300 hours/year. Actual annual emissions from Keystone, Crown/Vista and existing resources depend on their actual generation.

Table 4: Externalities of Air Emissions based on Massachusetts DPU Externality Valuation

Pollutant	MA DPU Ext Value (1994$) [a]	cents/kWh [b]			
		Freehold	Keystone	Crown Vista	Existing Coal
SO2	0.90	0.01	0.14	0.16	1.19
NOx	3.82	0.06	0.63	0.63	4.20
VOC	3.13	0.02	0.01	0.01	0.01
TSP	2.34	0.02	0.04	0.04	0.17
CO	0.51	0.01	0.05	0.05	0.01
CO2	0.01	1.15	2.57	2.60	2.93
Total cents/kWh		1.26	3.44	3.49	8.52
Total $/year [c]		11,505,943	31,374,400	31,869,153	77,727,623

Notes:

Values for CH4 and N2O have been omitted, because emissions factors were unavailable. The total external costs of these pollutants are generally small for power plants.

[a]: State externality values as explained in Table 2, expressed in 1994$/lb.

[b]: Cents/ kWh calculated as [emissions (lbs/MWh) from Table 1] × [a].

[c]: For comparison, total $/year is the product of total cent/kWh values and annual generation of 912500 MWh, the annual operation of the 125 MW Freehold Cogeneration Project for 7300 hours/year. Actual annual emissions from Keystone, Crown/Vista and existing resources depend on their actual generation.

Table 5: Externalities of Air Emissions based on New York PSC Externality Valuation

Pollutant	NY PSC Ext Value (1994$) [a]	cents/kWh [b]			
		Freehold	Keystone	Crown Vista	Existing Coal
SO2	0.49	0.00	0.08	0.09	0.65
NOx	1.09	0.02	0.18	0.18	1.19
PM10	0.20	0.00	0.00	0.00	0.01
CO2	0.00	0.06	0.13	0.13	0.15
Total cents/kWh		0.08	0.39	0.40	2.01
Total $/year [c]		749,751	3,546,876	3,673,931	18,329,920

Notes:

Water and land use values were assumed to be equivalent for these supply resources and have been omitted from this comparison.

[a]: State externality values as explained in Table 2, expressed in 1994$/lb.

[b]: Cents/ kWh calculated as [emissions (lbs/MWh) from Table 1] × [a].

[c]: For comparison, total $/year is the product of total cent/kWh values and annual generation of 912500 MWh, the annual operation of the 125 MW Freehold Cogeneration Project for 7300 hours/year. Actual annual emissions from Keystone, Crown/Vista and existing resources depend on their actual generation.

Table 6: Environmental Costs of Pollution per kWh

Pollutant	State	Cost (1994$/lb)	cents/kWh Freehold	Keystone	Crown Vista	Existing Coal
NOx	New Jersey	0.90	0.01	0.15	0.15	0.99
	Massachusetts	3.82	0.06	0.63	0.63	4.20
	New York	1.09	0.02	0.18	0.18	1.19
SO_2	New Jersey	2.22	0.02	0.34	0.39	2.93
	Massachusetts	0.90	0.01	0.14	0.16	1.19
	New York	0.49	0.00	0.08	0.09	0.65
PM10	New Jersey	1.30	0.01	0.02	0.02	0.10
	Massachusetts	2.34	0.02	0.04	0.04	0.17
	New York	0.20	0.00	0.00	0.00	0.01
CO_2	New Jersey	0.01	0.67	1.50	1.51	1.71
	Massachusetts	0.01	1.15	2.57	2.60	2.93
	New York	0.00	0.06	0.13	0.13	0.15
VOCs	Massachusetts	3.13	0.02	0.01	0.01	0.01
Total	New Jersey		0.71	2.01	2.07	5.72
	Massachusetts		1.26	3.44	3.49	8.52
	New York		0.08	0.39	0.40	2.01

Notes

This table shows the environmental costs, according to the valuation of three northeastern states, (1) in dollars per pound of pollutant, and (2) in cents per kWh of electricity generated at each power plant. The derivation of all values is explained in Tables 3, 4, and 5.

EXHIBIT C

RECYCLED

The agency proposal follows:

Summary

The Board of Public Utilities (Board) has adopted a series of initiatives over the past decade to foster an expanded penetration of energy efficiency and load management measures into the homes and businesses of the State. Specifically, the Board has approved a number of utility conservation programs designed to provide rebates, grants, loans and other incentives for residents and businesses to purchase and/or install conservation measures. In 1988, the Board approved a competitive bidding procedure whereby electric utilities in the State periodically issue Requests for Proposals (RFP) to solicit non-utility supply-side and demand-side projects to meet forecasted needs for additional capacity and energy. As a result of this procedure, a number of contracts have been executed between electric utilities and energy service companies for delivery of demand-side management (DSM) capacity and energy savings.

In addition, the Board has elsewhere in this issue of the New Jersey Register proposed N.J.A.C. 14:12, Demand Side Management Resource Plan rules, by which certain incentives would be provided to electric and gas utilities to encourage promotion of and investment in energy conservation measures. These expanded conservation initiatives are expected to be implemented in large part by contractors, energy service companies and other third parties participating in utility-sponsored programs.

In addition, the Board is of the opinion that utility customer lists and related billing information should be made available to qualified participating contractors in order to render the marketing of these programs more efficient. The proposed new rule would require that utilities make such customer information available to contractors, energy service companies or other parties who are procured by the utility to market, install or otherwise provide demand side management services to utility customers.

It is the view of the Board that such information has been developed through efforts supported by ratepayer funds. Accordingly, to the extent that the effectiveness of DSM programs can be improved through the controlled release of such information to the benefit of ratepayers, said release is appropriate.

Social Impact

The proposed new rule is intended to enhance the ability of third parties involved in the marketing, installation or other provision of DSM services to utility customers to efficiently identify eligible customers. This will improve the cost-effectiveness of DSM programs, which enures to the benefit of utility ratepayers, and will also enhance the ability of third party energy service companies and contractors to compete with utilities for the provision of DSM services. The increased cost-effectiveness of DSM programs and enhanced competition in the energy services market will lead to greater penetration of energy efficiency measures, thereby resulting in lower customer bills, reduced need to site and construct or purchase new energy supply facilities, as well as reduce combustion of fossil fuels. This will, among other things, improve the environmental quality of the State as well as reduce the State's dependence on imported energy sources.

Economic Impact

The proposed new rule will have negligible economic impact on utilities since the information already exists. Energy service companies and contractors stand to benefit by enhancing their ability to identify potential customers for DSM services. In order to avoid potential negative impacts on utility customers, the proposed rules prohibit disclosure of customer information by contractors. It is not the intent of the proposed rules that such sensitive information be disseminated publicly.

Regulatory Flexibility Statement

The proposed new rule does not require a small business regulatory flexibility analysis since it does not specifically apply or impact on small businesses as defined under the Regulatory Flexibility Act, N.J.S.A. 52:14B-16 et seq. The proposed rules place requirements only on investor-owned electric and natural gas utilities in the State all of which are large businesses in that they are the major energy utilities in the State and employ individually over 100 employees. Indeed, the rules require that the utilities take steps to enhance business opportunities for energy service companies and equipment suppliers and installers, many of which will likely be small businesses and will be positively impacted.

Full text of the proposed new rules follows:

SUBCHAPTER 6. CUSTOMER LISTS AND BILLING INFORMATION

14:12-6.1 Release of information

(a) Upon execution and award of a Demand Side Management (DSM) contract by a utility to a qualified energy service company (ESCO) to procure delivery of DSM services, a utility shall have available, at the request of said ESCO, utility customer lists and usage information related to the target customer group, subject to the following:

1. That said energy service company shall agree that release of such customer information to other entities or members of the public is expressly prohibited;

2. That use of said information for purposes other than those directly related to the execution of the contract with the utility to deliver energy services is expressly prohibited;

3. The customer list and usage information shall be treated as confidential throughout the DSM project and shall not be duplicated or distributed beyond those ESCO employees directly involved on the DSM project; and

4. Upon completion of the DSM project all information related to customer listings, usage etc., so provided shall be returned to the Company.

(b) The utility shall require each affected ESCO to enter into a protective agreement which includes the provisions set forth in (a) above, prior to the release of customer list and usage information.

(a)

BOARD OF PUBLIC UTILITITES

Demand Side Management Resource Plan

Reproposed New Rules: N.J.A.C.14:12

Authorized By: Board of Public Utilities, George H. Barbour and Jeremiah F. O'Connor, Commissioner.

Authority: N.J.S.A. 48:2-12 and 13; 52:27F-1(g) and (q); and 52:27F-18.

BPU Docket Number: EX90040304..

Proposal Number: PRN 1991-245.

A **public hearing** concerning this reproposal will be held on:

May 23, 1991 at 10:00 A.M. at:
Newark City Hall
Council Chambers Room
920 Broad Street
Newark, New Jersey 07102

Submit written comments by June 6, 1991 to:

Robert Chilton, Director
Electric Division
Board of Public Utilities
Two Gatetway Center
Newark, New Jersey 07102

The agency proposal follows:

Summary

A rulemaking pre-proposal entitled "Limiting Barriers to Effective Conservation Progress and Implementing Conservation Ratemaking Incentives," Docket No. EX90040304, was published in the June 4, 1990 New Jersey Register at 22 N.J.R. 1692(a). This pre-proposal identified the existence of certain barriers to more extensive investment in energy conservation by consumers and utilities in the State. It also outlined possible utility ratemaking incentive mechanisms to remove some of the existing barriers and to encourage energy conservation investments. The pre-proposal posed questions regarding the aformentioned subjects in order to elicit comments.

A public hearing was held by the Board of Public Utilities (Board) at its offices in Newark, New Jersey on June 25, 1990. A certified court reporter was present at the hearing and a complete transcript was produced and was made a part of the record of this proceeding. The record remained open for written comments until July 9, 1990.

It was the view of the majority of the commenters on the pre-proposal that the provision of some form of financial incentives to the utilities would foster an increased penetration of installed conservation, load management and energy efficiency (demand side management or "DSM") measures in the homes and businesses of the State. It was generally agreed that given the existing barriers to the full development of cost-effective energy efficiency technologies, including lack of information, lack of available capital and insufficient payback periods for many customers, utilities can play an important role in expanding the role of DSM in meeting the State's energy needs.

It is noteworthy that a number of other states, including New York, California, Wisconsin, Florida, Massachusetts, Washington and Rhode Island, have instituted programs designed to provide some form of incentives for utilities to actively encourage the installation of DSM measures in their service territories. While a conclusive finding on the ultimate success of these programs is impossible because of their relatively short lives, it is clear that DSM activity has increased dramatically in those states where incentive programs have been implemented.

The concept of least cost utility planning (LCUP) has gained wide acceptance in utility regulatory jurisdictions throughout the country in recent years. The principles of LCUP hold that utilities should pursue those resources which permit them to continue to provide safe and reliable service at the lowest possible cost. For example, in addition to the myriad of supply-side technologies available to utilities to meet growing customer demands for energy, DSM measures offer an alternative resource which can be tapped to offset the need for new electric generating and transmission plant or natural gas supply sources and transmission facilities, and the concomitant environmental impacts. In short, imbalances between projected customer demands and electric and natural gas supplies can be addressed in one of two general ways: either by increasing supply or by reducing customer demands through installation of DSM measures. LCUP requires that the utility pursue the combination of supply and demand side resources which allows the maintenance of safe and reliable service at the lowest overall cost. Moreover, to the extent practicable, the determination of the overall cost of various resources should reflect the impact of each on environmental quality.

In order to encourage an increased emphasis on DSM technologies as a viable alternative to construction and procurement of new supply-side facilities, the Board has previously instituted initiatives which foster the application of utility least cost planning principles. Specifically, the Board has approved conservation plans for the implementation of certain programs which to accomplish numerous DSM objectives including the performance of energy audits and the provision of energy information, appliance rebates, subsidized loans, and grants. Further, in 1988, the Board adopted a bid solicitation procedure for New Jersey electric utilities (Docket No. 8010-687B). Under this procedure, electric utilities annually identify a block of future capacity which is met through an integrated competitive bid solicitation for DSM and non-utility generator projects. The procedure is designed to foster the selection of the combination of supply and demand side projects which, subject to certain criteria including environmental, project viability and reliability minimize the ultimate cost to ratepayers. A Request for Proposals (RFP) is approved for release by the Board which provides project weighting criteria for supply and demand side bids. Price bids are capped at the utility's avoided cost, and points are awarded on a sliding scale for bid prices below avoided cost. In addition to price, weighting criteria include, inter alia, environmental impacts, fuel diversity and project viability. Payments by the utilities to the projects under approved power purchase agreements are permitted to be recovered from customers on a one-for-one basis through the annual fuel clause. This differs from the rate treatment accorded utility-constructed plant, which is placed in rate base with its cost recovered over its useful life and with an opportunity for the utility to earn a return on its investment.

The bid solicitation process has led to increased integration of the utility resource planning process, wherein supply and demand-side projects are intended to be considered on an equal and competitive basis and where the outcome produces a combination of the two which maximizes the benefits to utility ratepayers and society at large.

In order to further enhance the integrated resource planning process in the State, the Board is of the view that a ratemaking plan should be instituted which would provide the electric and gas utilities in New Jersey with at least the same level of financial incentive which now exists for the addition of new supply-side resources.

The comments received in the pre-proposal stage generally supported the concept of providing financial incentives for utilities to implement DSM programs, that is, to remove the sales erosion disincentive and provide utilities with the opportunity to earn a return on investments in DSM measures. Indeed, a number of the utilities in response to the pre-proposal set forth an outline for incentive programs which they would propose in response to rules permitting such activities. The diversity of the program outlines provided underscores the need for flexibility in any rules which may be promulgated in order to afford utilities some latitude in fashioning programs to meet the needs of their respective service territories. Nonetheless, there is also a need for a regulatory model to ensure that the various initiatives designed by the utilities conform with public policy goals.

To that end, the Board proposed new rules N.J.A.C. 14:12 entitled "Demand Side Management Resource Plan" in BPU Docket No. EX90040304. Said proposal was published in the December 17, 1990 New Jersey Register at 22 N.J.R. 3699(a). The proposed rules provided utilities with the opportunity to recover program costs and lost revenues, and to earn returns on investments in energy efficiency measures based upon a sharing of program savings between utilities and ratepayers. The proposed rules also included methodologies for measuring costs, benefits and levels of incentives, as well as a proxy approach for valuing environmental externalities.

A public hearing concerning the proposed rules was held on December 20, 1990, and written comments were received through January 16, 1991. A majority of the comments can be placed into three main categories. First, independent plumbing, heating and cooling contractors expressed strong opposition to the proposed rules because of their perception that the rules were intended to encourage utilities to directly sell, install and maintain high efficiency appliances and other measures to the exclusion of small businesses. Second, utilities expressed concerns regarding the applicability of the various cost benefit methodologies and the interaction of utility programs with programs being administered by energy service companies as a result of the utilities' competitive bidding solicitations. Third, energy service companies expressed concerns that the proposed rules would permit utilities to monopolize the energy service market thereby eliminating many of the benefits which result from the existing competitive bid process. Various other comments were received concerning the appropriateness of proposed core programs, quantification of environmental externalities and other issues. In addition, Public Service Electric and Gas (PSE&G) reiterated its desire to implement a standard price offer for DSM projects as opposed to the shared savings approach. Moreover, in approving PSE&G's 1990 competitive bidding filing, the Board committed to resolving the so-called "double-count" bill savings issue. Based on these comments, substantial revisions to the proposed rules have been made, thereby requiring additional public notice and comment. The current proposal, therefore, supersedes and replaces the proposal at 22 N.J.R. 3699(a). It should be noted that N.J.A.C. 14A:20, proposed for repeal in the original proposal, expired on Februry 3, 1991, pursuant to Executive Order No. 66 (1978). Therefore, no repeal action is necessary.

The Board is committed to assuring that independent contractors, suppliers and energy service companies have a meaningful, and indeed, a central role in the implementation of energy conservation programs. The Board believes that, while utility expertise and resources should play a vital role in designing and marketing programs, the continued use of financial incentives and reliance on the non-utility infrastructure for the direct installation of measures is an appropriate means by which utilities may deliver energy conservation services. To that end, the effect that utility conservation programs have on competitive markets will be an important factor considered by the Board and its staff in reviewing proposed DSM plans.

At the public hearing on December 20, 1990, Commissioner Scott A. Weiner, then President of the Board, questioned the appropriateness of utilities being in the business of directly selling and installing appliances or energy conservation measures, except in unique circumstances where no sales, delivery and/or installation mechanism for a particular measure existed and that a rulemaking to that effect should be explored. It was the conclusion of subsequent legal research, however, that the Board does not have the jurisdiction to ban utilities from such activities. Therefore, the Board will not prohibit utilities from explicitly servicing or installing appliances or energy conservation measures. Legislative changes would be necessary to provide the necessary jurisdiction. However, the Board will continue to oversee such activities to ensure that the charges are reasonable and to ensure there is no cross-subsidization of these activities. Moreover, the BPU can and will carefully review the impact of utility DSM programs on existing competitive supply, distribution and installation markets. It should also be noted that during the comment period the utilities repeatedly stated their intent to utilize third parties to supply and install the bulk if not all of program measures.

The Board believes that the proposed rules will result in benefits to all sectors of the energy services market, including the creation of jobs for small and independent contractors and distributors. The proposed rules are intended to foster an expanded investment in energy efficiency measures in the State which will replace the construction of generating facilities and fuel purchases which could result in a flow of dollars out of the State.

It is the Board's conclusion that the goal and intent of the proposed rules was not clearly expressed in the original proposal, thus leading to the strong objection and justifiable concerns expressed by the contractors. The language in the reproposed new rules has been clarified to specifically state the Board's intent to maintain and enhance a competitive supply, distribution and installation market. References to a particular minimum block or percentage reserved for independent contractors, which was the subject of concern among a large component of the commenters, has been omitted.

The major issues addressed by the utilities involved the applicability of the various cost benefit tests required to be filed, as well as the interaction of utility DSM programs with the programs being implemented by energy service companies (ESCO(s)) as a result of the utilities integrated bid (supply and demand) solicitations for capacity and energy.

In response to these concerns, certain modifications to the proposed rules were made. Applicability of the various cost benefit methodologies has been defined as establishing a formula for determining incentives and requiring that program measures pass the "Total Resource Cost" test as defined in the proposed rules. The rules have been modified to allow for standard pricing offers to be used. This would permit PSE&G, as well as other utilities, to implement the standard price offer concept espoused in its comments. It is the Board's view that at the outset, a variety of concepts should be explored in order to gather a broad range of experience. The role of competitive bidding for DSM projects has also been clarified in the proposed rules. The new proposed rules maintain flexibility in order to allow a utility to design a DSM program that meets its specific capacity and energy needs.

Several modifications have been made which address the concern of the ESCOs that the proposed rules will allow utilities to monopolize the energy services market. These modifications include the addition of an option for a utility to use standard offers as a means of procuring energy savings. Standard offers would also be made available to ESCOs at prices and terms equivalent to those given to utilities.

If a utility opts for the shared savings approach, which provides the utility with greater control over program design and pricing, the utility would be required to continue to issue an integrated (supply and demand) bid as required by the Stipulation of Settlement. The Board believes that both approaches will result in ESCOs playing a significant role in the energy services market. Further, the Board in its continued oversight of utility programs, can insure that the programs will enhance rather than discourage the role of ESCOs in the delivery of energy services.

The reproposed new rules set forth herein include the following additional provisions.

The proposed rules provide for the electric and gas utilities in the State to file, biennially, a Demand Side Management Resource Plan (Plan) for review and approval by the Board. Within the Plan, the utilities are required to propose an overall savings target for the Plan, and a series of "Performance-Based DSM Programs." These programs will provide each utility with the opportunity to earn returns on investments in energy efficiency measures based upon the actual performance of the programs. Performance will be evaluated by comparing the costs associated with each program to the benefits derived from the program (defined as avoided cost savings to the utility plus environmental benefits). For standard offer programs, utilities will have an opportunity to earn profits based on the difference between the cost of the program and the standard offer payment. Along with the program descriptions, each affected utility will be required to file a program implementation plan, a performance measurement and verification plan for each performance-based program, an avoided cost study, and a proposed cost recovery mechanism to permit the timely recovery of program costs through rates.

The avoided cost studies utilized in developing the incentives must be consistent with studies used to evaluate other utility resource acquisitions. It is recognized there has been less experience to date with calculations of avoided costs for natural gas utilities in the State than for electric utilities. The gas savings valuation methodologies employed in the August 1990 New Jersey Conservation Analysis Team (CAT) Report represent a substantial effort toward the development of avoided cost studies for gas and should provide guidance to the gas utilities and the Board in preparing and reviewing the DSM Plans.

The framework for utility shared savings incentives provided for in the proposed rules offers two general options. First, consistent with the originally-published rules, utilities will be allowed the opportunity to earn incentives based upon a shared savings of a portion of the program's net benefits. A second option by which utilities may earn incentives is via the standard pricing offer approach. A standard price offer can be developed and made available for utility programs and for programs implemented by ESCOs, other third parties and end users who meet certain minimum requirements. The price will be based on avoided cost and will include adjustments for environmental externalities and lost contributions to fixed revenues. Profits will result to the extent that savings are delivered at a unit cost below the standard price.

The proposed rules provide an important distinction between the standard offer approach and the shared savings approach. If a utility opts for the standard offer approach, it must make standard offers available to all ESCOs and host facilities that meet the minimum criteria established. A standard offer of broad scope and application can be expected to bring forth a large block of cost-effective DSM measures, thus supplanting the need for an integrated bid. Moreover, it is the Board's view that a broad standard offer and competitive bid cannot simultaneously coexist, because of problems associated with different players in the market receiving different price signals. On that basis, if a utility requires additional capacity and energy, and opts to procure it through a competitive solicitation, the utility will not be required to issue an integrated (supply and demand side) bid.

If a utility opts for the shared savings approach, however, there is no guarantee that the market potential for DSM will be fully exploited, since the scope and penetration of measures is more directly controlled. On that basis, if a utility chooses this option, any competitive bid solicitation will be required to continue to be integrated (supply and demand side).

In order to introduce a degree of risk sharing and allocation commensurate with the opportunity for earning incentives, the proposed rules provide for utilities to incur negative incentives to the extent that program costs exceed program benefits.

The establishment of a methodology by which the cost-effectiveness of DSM programs is ascertained, and the adoption of a basis for utility incentives, presents a regulatory dilemma. The total resource cost (TRC) test has gained wide acceptance in other jurisdictions. It was the primary test used to judge the cost-effectiveness of New Jersey utility programs in the August 1990 Conservation Analysis Team (CAT) study, and it was advocated for use by a number of utilities and other commenters to the proposed rules published at 22 N.J.R. 3699(a). The TRC test analyzes programs from a societal viewpoint, essentially holding that, in order to be cost effective, the total cost of a DSM program as measured by utility program costs plus contributions by a participant must not exceed utility avoided cost savings, related line losses and reserve margin savings, and incidental savings (plus externalities where included). Because bill savings represent a benefit to the participant and a cost to the non-participating ratepayer, from a societal standpoint this component nets out.

While it is appropriate for the Board to consider DSM programs from a societal perspective—ensuring that efficient programs are pursued—the impact of programs on utility costs and rates cannot be ignored. From the perspective of non-participating utility ratepayers, the erosion of revenues resulting from an individual utility customer undertaking energy conservation will put upward pressure on their rates, at least in the short run, as they pick up a greater share of the utility's fixed cost. One approach by which to mitigate this effect is to make DSM programs universal, so that essentially every customer has the opportunity to become a participant and therefore lower his or her bill. Thus, while rates may increase, the total bills of customers or total cost of the utility declines. However, while this is a worthy goal, it cannot be assumed that all customers, no matter how broad a range of programs is offered, will participate. As a result, while the TRC remains an appropriate measure of cost-effectiveness, the impact of DSM programs on utility rates should be given consideration as well.

To that end, the proposed rules establish the TRC as the determinant of the cost-effectiveness of a program. A program must be demonstrated to pass the TRC in order to gain initial approval. However, the proposed rules establish a formula to determine the appropriate level of utility contribution toward a DSM measure which takes into account rate impact. The appropriate level of utility contribution will be determined by subtracting fixed cost revenue erosion (considered as a cost) from the sum of avoided cost savings, associated line loss savings and reserve margin savings, incidental savings and environmental externalities (considered as benefits). Fixed cost revenue erosion is determined as the average retail rate of the utility less gross receipts and franchise taxes and fuel costs, all multiplied by 0.8. By applying a multiplier of 0.8 to fixed costs revenue erosion, the Board is allowing for a small increase in rates. However, programs of broad application should be offered to afford each customer the opportunity to participate and therefore lower his or her overall bill. Such broad opportunities will enable businesses to avail themselves of energy efficiency technologies which lower overall bills and thereby improve competitiveness, and will also allow residential customers and governmental bodies to reduce energy bills.

The appropriate level of utility contribution, as determined by the above-described formula, will be used as both the basis for utility shared savings mechanisms and the standard pricing offer. Additional contributions from participating customers, in the form of direct payments or shared savings, will be permitted up to the point where the total of utility payments (costs) plus participant costs equals the benefits as defined in the TRC (avoided costs, related line losses and reserve margin savings, incidental savings and environmental externalities).

The rules also provide a framework to reflect the potential environmental benefits associated with DSM technoloiges. The quantification of environmental costs associated with electric generation and natural gas combustion is an evolving endeavor. Three states, New York, Massachusetts and Nevada, have adopted specific values for environmental externalities for inclusion in the least cost planning process of utilities. The Board also takes note of a 1990 Report prepared by the Pace University Center for Environmental Legal Studies for the New York State Energy and Developmental Authority and United States Department of Energy, which studied the existing literature valuing environmental costs of electric utility operations. Driven primarily by air pollution costs related to SO_2, NO_x, particulates and CO_2, the report develops environmental costs for coal-fired, natural gas fired and oil-fired generating facilities, among others. To summarize, the Pace study establishes environmental costs of $.045 per kilowatt-hour (kwh) for a coal-fired facility meeting new source performance standards (NSPS), $0.11 per kwh for a gas-fired combined cycle facility, $.03 per kwh for an oil-fired combustion turbine and $.032 per kwh for a steam plant burning low sulfur oil. It should be noted that the environmental externality values adopted in Nevada and Massachusetts closely follow the figures established in the Pace Report.

Making the conservative assumption that all coal-fired units from which New Jersey utilities purchase electricity meet NSPS (which will not be the case for a number of years), and employing a weighted average of New Jersey electric fuel mix (including purchases) of 50 percent coal, 10 percent gas and 10 percent oil, electric generation produces an average air pollution environmental cost of 2.65 cents per kwh. However, the predominant marginal generating unit technologies appearing in the New Jersey utilities' capacity plans are natural gas-fired combustion turbines or combined cycle units. The Pace Report estimates the environmental cost of generation from the avoided production plant is more on the order of 1.0 cent per kwh. However, the avoided gas-fired combustion turbine or combined cycle facility would be expected to run from several hundred to several thousand hours per year predominantly during peak and shoulder periods. As a result, baseload energy efficiency DSM measures can be expected to avoid generation from existing plant, likely coal-fired facilities, during off-peak hours.

In consideration of the factors noted, the proposed rules establish an average value for electric environmental externalities of 2.0 cents per kwh. The rules also provide for time differentiation of environmental costs to take into account the previously enunciated factors.

For natural gas, the value for environmental externalities is established in the proposed rules at $.95/MMBtu (one million British thermal units), which approximates the environmental costs established in the Pace Report for natural gas combustion at an electric generating facility. As with the electric figures, this value is considered conservative since the gas-fired electric generating unit is assumed to have various emission controls not present at natural gas end user premises.

It is recognized that the environmental values established in the proposed rules represent merely an approximation, and will likely be the subject of further study and refinement. However, it is important that a starting point be established for purposes of assessing the benefits of DSM programs. The proposed rules provide for modification of these values in future DSM plan filings as the base of information in this field evolves.

The rules also specify a number of specific conservation programs which the utilities are required to undertake in an attempt to maximize potential public benefits and in recognition of the difficulty in accurately quantifying the full benefits of such programs. These programs are designated as "Core Programs." The utilities are provided the flexibility to incorporate any of the specified programs in the Core section into the incentive-based program section if it can be demonstrated that said programs are cost-effective and that savings can be adequately measured. Some utilities objected to certain of the Core Programs, based upon their poor performance as assessed in the CAT study. However, the proposed rules do not require that all existing utility programs be continued, and they also provide the flexibility to incorporate program modifications recommended in the CAT study to improve overall cost-effectiveness.

The proposed rules also provide each utility the opportunity to file, for review and approval by the Board, a proposed revenue adjustment mechanism to account for revenue erosion associated with DSM efforts. The loss of revenues and the resultant loss in contribution towards fixed cost resulting from conservation measures has the potential to create a short-term disincentive for utilities, to the extent that earnings are negatively impacted.

Each utility will be required to file a "Transition Strategy" which describes the utility's planned merger of existing DSM efforts with the proposed DSM Plan.

Finally, the proposed rules require each gas utility to file a proposed pilot procedure for the implementation of a competitive bid solicitation process or standard price offer for procurement of demand side load reductions. The Board recognizes that currently there is no established procedure for the implementation of a competitive bid solicitation for DSM measures by natural gas utilities in the State similar to the present integrated bidding system for electric utilities. The structure and nature of the natural gas supply industry in 1991 is such that a competitive bidding procedure which includes solicitations for purchases from third party gas suppliers is not necessary or appropriate, since there already exists substantial competition for wellhead supplies. However, the implementation of a bidding system or standard price offer for procurement of DSM measures in natural gas customer end use applications holds promise for fostering the development of a natural gas ESCO market much as the electric bidding system has done. There is no inherent reason that a bid solicitation or standard price offer for natural gas DSM measures should prove substantially more problematic than bidding for electricity DSM applications. There is, however, a smaller universe of potential DSM applications on the natural gas side than with electricity. Nonetheless it is the belief of the Board that a smaller potential universe, while effecting the possible size and scope of bid solicitations, should not preclude the implementation of such a procedure. As a result, the proposed rules require each gas utility to prepare a pilot DSM bidding or standard price offer procedure. It is recognized that the long-term coexistence of separate DSM bidding procedures and utility-based incentive programs is still in question. The pilot nature of the natural gas bidding procedure reflects the need to gain more experience in this regard.

The rules proposed herein represent a more current and comprehensive regulatory model concerning the implementation of conservation programs by utilities in the State than the expired conservation rules in N.J.A.C. 14A:20 which had been promulgated by the former Department of Energy. On June 15, 1989, then Governor Thomas A. Kean issued a Reorganization Plan (No. 002-1989) to provide for the increased coordination and integration of the State's energy regulation, planning and policy formation by the State through the transfer of the Division of Energy Planning and Conservation (Division) from the Department of Commerce, Energy and Economic Development to the Board (see 21 N.J.R. 1937). Pursuant to the plan, the Division, together with all its existing functions, powers and duties, was continued and transferred to the Board. Among those duties was the responsibility and authority to design, implement and enforce a program for the conservation of energy in commercial, industrial and residential facilities. Because the proposed new rules would render the continued application of N.J.A.C. 14A:20 duplicative, the expiration of N.J.A.C. 14A:20 will be allowed to stand.

Social Impact

The reproposed new rules are intended to lead to the accelerated implementation and installation of energy efficiency measures in the homes and businesses in New Jersey, by providing electric and natural gas utilities incentives to take a proactive role in encouraging energy conservation. The accelerated proliferation of energy efficiency on the part of electric and gas utilities and their customers is intended to, among other things, reduce customer bills, reduce the need for siting and construction of new energy supply facilities and reduce the combustion of fossil fuels, thereby improving the environmental quality of the State, as well as reducing the State's reliance on imported energy sources. The proposed rules are also intended to ensure that activities to assist low income energy consumers will continue and even expand. Finally, the proposed rules are intended to insure the development of a competitive market for the delivery of conservation programs where appropriate.

Economic Impact

The reproposed new rules will have a positive economic impact on the State's investor-owned electric and gas utilities by creating opportunities for earning returns on investments in energy conservation activities which presently do not exist, and for mitigating the potential negative effects which now exist relating to sales erosion from energy conservation. The proliferation of utility-sponsored conservation activities will have a positive impact on the State's economy, by reducing overall utility bills and therefore enhancing the State's competitive position. Finally, but no less important, the rules are intended to create significant business opportunities for independent entities such as energy service companies and energy efficiency equipment suppliers and installers. As increased investment in energy efficiency will divert business from out-of-State bulk fuel suppliers to in-State providers of energy efficiency equipment, the overall economic impact on the State will be positive.

Regulatory Flexibility Statement

The reproposed new rules do not require a small business regulatory flexibility analysis since they do not specifically apply or impact on small businesses as defined by the Regulatory Flexibility Act, N.J.S.A. 52:14B-16 et seq. The rules place requirements only on investor-owned electric and natural gas utilities in the State, all of which are large businesses in that they are the major energy utilities in the State and employ over 100 employees. Indeed, the rules require that the utilities take steps to create business opportunities for energy service companies and equipment suppliers and installers, many of which will likely be small businesses and will be positively impacted.

Full text of the proposed new rules follows:

CHAPTER 12
DEMAND SIDE MANAGEMENT

SUBCHAPTER 1. PUBLIC UTILITY PROGRAMS

14:12-1.1 Purpose and scope

The rules in this chapter are designed to provide financial incentives to electric and gas utilities for investment in demand side management initiatives. These incentives are intended to foster the increased penetration of end-use energy efficiency technologies into the homes and businesses of the State. Increased energy efficiency is regarded as a viable alternative to the construction or procurement of new electric and gas supply sources. These rules are designed to put in place mechanisms which permit utilities to earn financial returns equivalent to or, in recognition of the potential positive impact on society, greater than the returns provided on supply side projects. It is further the intent of the rules to create an environment for utilities to utilize their resources and unique position as major energy providers in the State to foster increased energy efficiency while stimulating the further development and opportunities for independent energy service companies, contractors and suppliers to fairly compete for Demand Side Management (DSM) business opportunities.

14:12-1.2 Definitions

The following words and terms, when used in this chapter, shall have the following meanings unless the context clearly indicates otherwise.

"Avoided cost savings" means the level of fuel, operation and maintenance, labor costs, capital costs, taxes and any other costs which the utility avoids having to incur as a result of displacement of customer demands through demand side management efforts.

"Board" means the New Jersey Board of Public Utilities.

"Core Programs" means a set of conservation programs required to be performed by the utilities and which are not subject to the incentive ratemaking formulae established in N.J.A.C. 14:12-3. The Core Programs shall constitute activities undertaken by the utility in order to foster the dissemination of energy efficiency information to the public as well as to accomplish certain socially desirable or other public benefit goals.

"Demand side management (DSM)" means the control of a public utility's energy needs through the development of cost-effective energy efficiency technologies, including, but not limited to, installed conservation, load management and energy efficiency measures in the homes and businesses of the State.

"Demand Side Management Resource Plan (DSM Plan)" means a comprehensive presentation of a utility's demand side management activities over a specified period as well as mechanisms for DSM program cost and revenue erosion recovery and incentive mechanisms to encourage DSM activities as specified in N.J.A.C. 14:12-2, 3 and 4.

"Energy service company" means a company which provides energy efficiency and load management equipment and services to end user customers.

"Fixed cost revenue erosion" means the reduction in contribution towards a utility's fixed costs resulting from a reduction in energy usage from a DSM program. This figure is determined on a per unit basis by dividing total retail revenues minus the sum of gross receipts and franchise taxes and fuel costs by total retail sales.

"Free rider effects" means energy and capacity savings resulting from measures which would have been implemented even in the absence of the utility program.

"Fuel Adjustment Clause" means a mechanism through which a utility may recover its fuel costs on an annual basis. When used in this chapter, the term means specifically an electric utility's Levelized Energy Adjustment Clause (LEAC) or a gas utility's Raw Materials Adjustment (RMA) or Levelized Purchase Gas Adjustment (LPGA).

"Participant" means the end user at whose site the DSM measure or service will be installed or rendered.

"Penetration levels" means the amount of customer participation in a particular program relative to the eligible universe of customers for that program.

"Program measure" means the particular end use device, technology or service being offered within a particular program to be installed or rendered in the targeted customers' premises or in the utility's energy delivery system.

"Public utility" or "utility" means all electric and natural gas public utilities as defined by N.J.S.A. 48:2-13, but does not mean municipally owned electric or natural gas public utilities.

"Test year sales" means the level of sales utilized by the Board to set rates in the utility's most recent base rate proceeding.

"Total Resource Test" means a comparison of the avoided cost savings (including line loss factors and reserve margin savings), incidental savings and environmental externalities as benefits to the utility program and participant costs.

SUBCHAPTER 2. DEMAND SIDE MANAGEMENT RESOURCE PLAN

14:12-2.1 Filing

Every New Jersey electric and gas public utility subject to the jurisdiction of the Board shall file no later than 90 days from the effective date of this rule and by March 1, 1993 and every two years thereafter, a "Demand Side Management Resource Plan" (DSM Plan) for review and approval by the Board.

14:12-2.2 Plan elements

(a) The DSM Plan shall consist of the following elements, each of which shall be accompanied by technical support sufficient to provide the Board with a basis to evaluate the DSM Plan:

1. A target which establishes and specifies an overall energy and capacity savings goal in terms of kilowatt-hours (kwh) and kilowatts (kw) for electric utilities and therms for gas utilities to be achieved by virtue of the DSM Plan, as well as a specified time frame for attaining the goal;

2. An assessment of the effect of the Plan on the overall peak load and energy demand forecasts, construction plans, fuel purchase plans, capacity expansion plans and the future capital additions of the utility;

3. A list and description of "Performance-Based DSM Programs" which shall present the DSM efforts which the utility intends to implement over the succeeding two years and for which performance-based incentives will be sought pursuant to N.J.A.C. 14:12-3. DSM efforts proposed by the utility may include investments in increased energy delivery system efficiency in addition to end use efficiency;

4. A list, description and proposed budget for Core Programs which will be offered by the utility. As the benefits to be achieved from Core Programs may transcend a strict economic benefit/cost analysis or be difficult to accurately quantify, the Core Programs shall not be subject to the mechanisms applied to the Performance-Based DSM Programs as set forth in N.J.A.C. 14:12-3. Instead, the utilities will be permitted to expense the costs related to operation of the Core Programs on a timely basis through the DSM Cost Recovery Mechanism, as set forth in N.J.A.C. 14:12-4.1.

i. Unless otherwise directed by the Board, a utility's Core Programs menu must include the following:

(1) The Home Energy Savings Program (HESP) as described in N.J.A.C. 14:38. However, in order to increase the overall cost effectiveness of the Program, the utility may incorporate features such as target marketing, and prescreening of applicants to ensure that an otherwise eligible applicant has not had a prior utility—sponsored energy audit within a specified number of years at his or her present location, or does not reside in a residence that was constructed after a specified date;

(2) A Low Income Direct Grant and/or Seal-Up Program;

(3) A Commercial and Apartment Conservation Service (CACS) energy audit program; features similar to those described in (a)4i(1) above which enhance program cost effectiveness may be incorporated by the utility;

(4) A program encouraging the energy efficient design of new construction;

(5) Informational programs designed to foster conservation awareness;

(6) Educational programs designed to enhance the understanding of energy efficiency in the school systems;

(7) A program or package of programs offered by each electric utility directed at those residential customers within its service territory who utilize energy sources other than natural gas for space heating purposes; and

(8) Other programs as proposed by the utility or interested party and as deemed appropriate by the Board.

ii. In filing its DSM Plan, each utility shall have the opportunity to propose one or more Core Programs as a performance-based program, it being the intent of this section not to preclude the opportunity to earn incentives if an adequate measurement plan is provided by the utility.

5. For each Performance-Based DSM Program and Core Program, the DSM Plan shall include the following:

i. A program implementation plan, which shall include:

(1) The anticipated manner of the marketing and installation of program measures;

(2) Indications as to whether or not utility personnel or third parties are anticipated to actually perform the marketing, supply, installation or maintenance of program measures;

(3) In the event that third parties will be utilized, a description of the selection process to be employed, and the standards to which the third parties will be held in performing work; and

(4) An analysis of the impact of the program on the competitive aspects of existing market infrastructures involved in the sales and installation or other provision of similar measures and/or services.

ii. The customer base which the program will target;

iii. The DSM program measures to be offered;

iv. The commitments or contributions which will be expected of customers; and

v. The penetration levels and overall energy and capacity savings expected to be achieved by each program.

6. Each utility must prepare an Executive Summary of its DSM Plan filing which provides a brief overview of the Plan including:

i. An overall target savings;

ii. A brief description of the programs offered, including the manner of implementation, the projected savings and a measurement plan;

iii. An incentive mechanism and/or standard price offer description;

iv. A basis for the incentives or standard offer, including a summary of avoided costs;

v. A cost recovery mechanism; and

vi. A revenue adjustment mechanism.

7. Each utility must demonstrate an effort to offer DSM program opportunities to all sectors of its customer base, or demonstrate why such a broad spectrum is not achievable.

SUBCHAPTER 3. INCENTIVES

14:12-3.1 Basis for incentives

(a) Unless otherwise approved or directed by the Board, the basis for the opportunity to earn an incentive shall take one of the following formats:

1. A base percentage return on investment as set forth in N.J.A.C. 14:12-3.4(e) for each Performance-Based Program. To the base return shall be added incentives based upon a shared savings of the achieved net benefits associated with the individual programs set forth in its Plan; or

2. A DSM standard price offer for general application or for particular DSM measures, which establishes a per unit price for energy and capacity savings which a utility will pay to third parties and/or receive through rates for DSM projects which meet minimum viability, technological, measurement and verification criteria. Such a standard offer energy and capacity price will be established based upon the criteria set forth in N.J.A.C. 14:12-4.3.

14:12-3.2 Net benefits

(a) Net benefits of the program shall be defined as the difference between the net present value of benefits associated with the program and the net present value of program costs.

(b) The net benefits calculation can be expressed utilizing the following formula:

$NB = NPV_B - NPV_C$, where

NB = net benefits

NPV_B = net present value benefits of the energy and capacity savings, calculated using the following formula:

$$\sum_{t=1}^{L} \frac{(E \times AEC)}{(1 + DR)^{t-1}} + \frac{(C \times ACC)^{t-1}}{(1 + DR)}$$

where

t = years

L = duration of program measure

E = kilowatt-hours (electric utilities) or therms (gas utilities) of energy avoided in year t by virtue of the DSM measures

C = kilowatts (electric utilities) or peak therms (gas utilities) of demand avoided in year t by virtue of the DSM measures

AEC = avoided energy cost (cents per kwh or cents per therm) as approved by the Board. In addition to energy costs AEC must include an adjustment for transmission and/or distribution line losses and a specific incorporation of environmental externalities as provided in N.J.A.C. 14:12-3.7.

ACC = avoided capacity cost including appropriate reserve margin savings, as approved by the Board

DR = discount rate

NPV_C = net present value of total costs as recovered from ratepayers, including program costs, base level of return and a factor initially set at 0.8 times the fixed cost revenue erosion as adjusted by the Board from time to time.

EXHIBIT D

i. If the REACH/JOBS participant meets the criteria at N.J.A.C. 10:82-2.8(b) for payment of child care through the disregard method, then the child care disregard is applied to that budget month in which the participant begins payment for child care costs.

7. Authorization of payment of child care costs through REACH/JOBS funds are limited to providers of child care who satisfy the criteria delineated in (c) through (f) below.

8. No payments are authorized for child care expenses incident to the employment of a non-needy caretaker relative.

(c)-(d) (No change.)

(e) In-home care rules are:

1. "In-home care" means care for a child in the child's usual home and may be used when this is the child care arrangement preferred by the participant.

2. The authorized rate for in-home care shall be provided for all services and supervision pertaining to the care of the children and is not for the performance of household tasks unrelated to child care. Payment shall not be authorized for services provided by a non-needy caretaker relative who resides in the same home as the child when that relative is legally responsible (for example, parent, adoptive parent or legal guardian) for any member of the eligible family; or an individual who is a member of the AFDC assistance unit.

i. The "REACH Home Approval Checklist" (see N.J.A.C. 10:81, Appendix A) shall be used to evaluate in-home care.

3. (No change in text.)

(f)-(h) (No change.)

PUBLIC UTILITIES

(a)

BOARD OF REGULATORY COMMISSIONERS

Demand Side Management Resource Plan

Adopted New Rules: N.J.A.C. 14:12

Proposed: May 6, 1991 at 23 N.J.R. 1283(a).

Adopted: October 9, 1991.

Filed: October 9, 1991, as R.1991 d.549, **with substantive and technical changes** not requiring additional public notice and comment (see N.J.A.C. 1:30-4.3).

Authorized By: Board of Regulatory Commissioners, Dr. Edward H. Salmon, Chairman and Jeremiah F. O'Connor and Carmen J. Armenti, Commissioners.

Authority: N.J.S.A. 48:2-12, 13, 52:27F-1(g) and (q) and 52:27F-18.

BPU Docket Number: EX90040304

Effective Date: November 4, 1991.

Expiration Date: November 4, 1996.

Summary of rulemaking history:

A pre-proposal entitled "Limiting Barriers to Effective Conservation Progress and Implementing Conservation Ratemaking Incentives", Docket No. EX90040304, was published in the June 4, 1990, New Jersey Register at 22 N.J.R. 1692(a). This pre-proposal identified the existence of certain barriers to more extensive investment in energy conservation by consumers and utilities in the State. It also outlined possible utility ratemaking incentive mechanisms to remove some of the existing barriers and to encourage energy conservation investments.

A public hearing was held by the Board of Public Utilities (Board) at its offices in Newark, New Jersey on June 25, 1990. A certified court reporter was present at the hearing and a complete transcript was produced and was made a part of the record of this proceeding. The record remained open for written comments until July 9, 1990.

The Board proposed new rules, N.J.A.C. 14:12, entitled "Demand Side Management Resource Plan" in BPU Docket No. EX90040304. Said proposal was published in the December 17, 1990 New Jersey Register at 22 N.J.R. 3699(a). The proposed rules provided utilities with the opportunity to recover program costs and lost revenues, and to earn returns on investments in energy efficiency measures based upon a sharing of program savings between utilities and ratepayers. A public hearing concerning the proposed rules was held on December 20, 1990, and written comments were received through January 16, 1991. In response to concerns expressed, certain modifications to the proposed rules were made.

The rules were reproposed on May 6, 1991 at 23 N.J.R. 1283(a) and represent a more current and comprehensive regulatory model concerning the implementation of conservation programs by utilities in the State than the existing conservation rules in N.J.A.C. 14A:20 which had been promulgated by the former Department of Energy. Because the proposed new rules would render the continued application of N.J.A.C. 14A:20 duplicative, N.J.A.C. 14A:20 was initially proposed for repeal and subsequently expired on February 3, 1991.

An open public meeting was conducted by the Commissioners on May 23, 1991 and comments on the proposed rules were received until June 6, 1991. No recommendations were made by the Commissioners. The proposed rule was adopted by the Board at its open public hearing held on September 25, 1991. A copy of the record of the public meeting may be reviewed or obtained by contacting:

Edward P. Beslow
Legal Specialist
Board of Regulatory Commissioners
Two Gateway Center
Newark, N.J. 07102

Summary of Public Comments and Agency Responses:

Written comments on the reproposed new rules were submitted by Nancy J. Zausner of Alternate Power Producers of New Jersey, W. Kenneth Cavender of Atlantic Electric Company, R. William Potter of Cogen Technologies, Frank T. Bahniuk of Elizabethtown Gas Company, James T.B. Tripp of Environmental Defense Fund, Curt Macysyn of Fuel Merchants Association of New Jersey, Dennis Baldassari of Jersey Central Power and Light Company, Michael A. Walker of Kraft & McManimon (representing a group of Energy Service Companies), Ernest H. Manual of Mathtech, Inc., Harry A. Bosshard of New Jersey State Council of Electrical Contractors Association, Nina Mitchell Wel[illegible] of New Jersey N.J.A.C. Department of the Public Advocate, Divisio[illegible] of Rate Counsel, William R. Watkins of New Jersey Industrial Ener[illegible] Users, Lindabury, McCormick and Estabrook, Thomas J. Kononowi[illegible] of New Jersey Natural Gas Company, Jane F. Kelly of New Jer[illegible] Utilities Association, Shawn P. Leyden of Public Service Electric a[illegible] Gas Company, Harry L. Kociencki of Roche Pharmaceuticals, John [illegible] Carley of Rockland Electric Company, Richard M. Esteves of SESC[illegible] Inc., David A. Kindlick of South Jersey Gas Company, S. Lynn Sutcli[illegible] of Sycom Enterprises and J. Mark Fox of Vision Impact Corporatio[illegible] Oral testimony on the proposed new rule was submitted by Renee G[illegible] of New Jersey Association of Plumbing, Heating and Cooling Contra[illegible]tors, Pat Chambers of Rockland Electric Company, Norman Adelm[illegible] of Coalition Against Unfair Utility Practices, Marvin Raber of Gene[illegible] Public Utilities Service Corporation, Frank Brill of North Jersey Chap[illegible] of the Air Conditioning Contractors of America, Michael Walker of Kr[illegible] & McManimon, William Tedesco of Bergen County Plumbing, Heat[illegible] and Cooling Contractors Association, Debra Di Lorenzo of New Jer[illegible] Business and Industry Association, Ken McKim of Wallington Plumb[illegible] Supplies, James J. Lees of Atlantic Electric Company, Ted Farinella [illegible] C.T. Farinella, Robert McCarton of Bergen County Plumbing and He[illegible]ing Contractors, John Jensen of Kenetech Energy Management, Rich[illegible] Basta of Associated Builders and Contractors, Jack Dalton of Hoffm[illegible] La Roche, Joseph Bowring of the New Jersey Department of the Pu[illegible] Advocate, Division of Rate Counsel, Fritz Lark of Public Service Ele[illegible] and Gas Company, Laura Giannotta of National Federation of Indep[illegible]dent Business, Art Lennon of EUA Cogenex Corporation, Daniel Ch[illegible] of New Jersey Plumbing Supply, Al Kania of Katzenberg Heating [illegible] Air Conditioning Company and The Air Conditioning Contractors [illegible]sociation of North Jersey and also the Coalition Against Unfair U[illegible] Practices, Clint Crane of Reel-Strong Fuel Company, and Donald [illegible] Natta of Van Natta Mechanical Contractors.

1. COMMENT: A majority of the commenters believe that [illegible] provision of some form of financial incentives to utilities will incre[illegible] the penetration of installed conservation, loan management and en[illegible] efficiency in the State. It was generally agreed that given the exi[illegible] barriers to the full development of cost effective energy efficiency [illegible]nologies, including lack of information, lack of available capital [illegible] insufficient payback periods for many customers, utilities can pl[illegible] important role in expanding the penetration of Demand Side Man[illegible]ment (DSM) in the State.

117. COMMENT: Any free-ridership discount should be agreed to before program implementation.

RESPONSE: N.J.A.C. 14:12-3.6(d) (proposed as N.J.A.C. 14:12-3.5(d)) has been modified to clarify the Board's intent that free rider effects shall be determined prior to program implementation and subsequent changes will apply only to prospective installations.

118. COMMENT: The provision that the Board or an interested party may request reconsideration of approved measurement plans in less than two years should be eliminated.

RESPONSE: The flexibility to adopt to changing technologies and experience is essential. However, N.J.A.C. 14:12-3.6(e) (proposed as N.J.A.C. 14:12-3.5(e)) has been modified to clarify that changes to measurement plans would apply only to prospective installations.

119. COMMENT: Will the costs of the verification contractors be allocated to the programs and used in the benefit/cost tests?

RESPONSE: Yes.

120. COMMENT: A program could fail a benefit-cost test because of the measurement method chosen. A high level of flexibility in the choice of estimation methods would encourage a greater diffusion of DSM measures.

RESPONSE: The proposed rules allow a high level of flexibility in the choice of methods for measurement and verification subject to Board approval.

121. COMMENT: The definition and identification of free-ridership is arbitrary. As free-ridership requires extensive research and analysis of DSM programs that yields highly debatable conclusions, it is recommended that free-ridership not be considered in the estimation plans.

RESPONSE: The Board concurs that it is difficult to quantify free rider effects. However, the Board believes it is important to adjust for this effect where it is known to exist and can be quantified, rather than to ignore the effects of free riders.

122. COMMENT: The Board should clarify that utility performance will be measured on a project by project basis.

RESPONSE: N.J.A.C. 14:12-3.6(a) (proposed as N.J.A.C. 14:12-3.5(a)) clearly states that a measurement plan is required for each DSM Program.

123. COMMENT: The funding of third party consultants through utility dollars in order for the Board to verify savings has been opposed. Instead, Board staff should be trained to perform this function.

RESPONSE: The costs associated with the verification of savings are legitimate costs that should be reflected in program costs.

124. COMMENT: The requirement in N.J.A.C. 14:12-3.6(g) that each utility shall fund the procurement of a verifying contractor is duplicative, because each DSM plan is required to set forth a measurement plan which will be pre-approved by the Board.

RESPONSE: While a pre-approved measurement plan is required, it is still necessary to verify that DSM measures have actually been installed and that the DSM program is delivering savings.

125. COMMENT: While any savings measure should be based upon actual savings rather than estimates, in situations where industry standards (that is, a furnace replacement) must be used, estimates might be useless if access to the type or condition of equipment being changed out is not available. Even if actual (metered) data is available, it can be degraded by the influence of free rider effects, which cannot be quantified.

RESPONSE: The Board prefers measured savings. However, for certain DSM measures, engineering estimates will be satisfactory. Utilities must require pre-installation audits to verify the type and condition of equipment being replaced.

126. COMMENT: The measurement plan as proposed gives preference to metering over engineering estimates. Engineering estimates should be equally acceptable because of the complexities (such as weather normalization) associated with metering.

RESPONSE: As this had always been the Board's intent, N.J.A.C. 14:12-3.6(c) (proposed as N.J.A.C. 14:12-3.5(c)) has been modified to clarify that if metering is impractical, engineering estimates are acceptable in conjunction with or as an alternative to metering.

127. COMMENT: There is objection to the requirement for independent contractor verification of utility performance based programs because such a requirement could be interpreted as 100 percent verification, which would be a duplication of effort. Furthermore, the level of utility funding is open-ended. If retained, the cost should be limited and the level of contractor activity more clearly defined.

RESPONSE: N.J.A.C. 14:12-3.6(g) (proposed as N.J.A.C. 14:12-3.5(g)) has been modified to clarify the role of the verification contractor. The level of verification and funding will be proposed by the utility subject to Board approval.

128. COMMENT: The inclusion as a benefit of two cents per kwh in connection with DSM programs for environmental externalities stacks the deck against non-participating ratepayers.

RESPONSE: The values included for environmental externalities reflect legitimate benefits that accrue to all ratepayers. Moreover, the formula of net benefits includes recognition of rate impacts.

129. COMMENT: The standard offer coupled with bill savings defines the total value of cost effective conservation. If appropriately set, no other cost effectiveness test is needed; therefore, the TRC test for the standard offer approach is unnecessary. Participants are protected by competition and freedom of choice and non-participants are not affected by participant costs and therefore don't need the TRC test.

RESPONSE: The Board believes that the TRC test is necessary for standard offer programs to insure that only cost effective DSM measures are installed.

130. COMMENT: Fuel switching should be addressed in the proposed rules.

From a Statewide view, technologies such as a desiccant air conditioner which conserves significant electricity and uses small amounts of gas are very beneficial. It conserves resources, reduces pollution and saves money for users. Also, this air conditioner replaces peak period electricity with off-peak gas.

Innovative efficiency proposals that involve redirection of electric utility primary fuel from electric utility boilers to end user sites should not be automatically dismissed as "fuel switching," as no primary fuel is actually switched. The long run marginal impact of electric consumption is the amount of new gas fired generation capacity needed and the level of natural gas consumption by electric utilities as primary generation fuel. There are significant losses in this conversion. The direct utilization by the end user is more efficient and provides increased environmental benefits especially with the phase out of electrically driven chillers which use chlorofluorocarbons. Gas fired chillers use no chlorofluorocarbons. Also, these result in long run benefits to gas deliverability in New Jersey.

RESPONSE: Fuel switching raises various issues that are beyond the scope of this proposal. Specific energy efficiency programs will be examined in the DSM plan review process.

131. COMMENT: An electric utility can use rebate money to promote all electric technologies at the expense of gas technologies. This can frustrate the goals of the State's program. Programs should be fuel blind and all technologies should be competing on an equal playing field.

RESPONSE: The Board concurs that DSM programs must be designed in a manner that promotes the installation of efficient appliances and that does not promote any one fuel over another. This will be an important component of the Board's plan review process.

132. COMMENT: Does the use of the Total Resource Test as the criteria to measure the benefit cost ratio mean that the Ratepayer Impact Test will no longer be necessary?

RESPONSE: The Ratepayer Impact Test is no longer specifically required. Ratepayer impact is addressed through application of the Fixed Cost Revenue Erosion Factor.

133. COMMENT: New Jersey Industrial Energy Users (NJIEU) objects to the Total Resource Cost test because it tilts the scales unreasonably in favor of DSM programs.

RESPONSE: The Total Resource Test insures that only cost effective DSM programs are implemented. The Net Benefits calculation determines the maximum payment to utilities and third parties from ratepayers. It is set equal to or less than a utility's supply alternative. The proposed rules include the provision of a "market factor" which enables the Board to reduce payments for DSM if deemed appropriate.

134. COMMENT: The estimate of environmental benefits should be used conservatively and not escalated over time.

Environmental externalities cannot be considered in isolation from other resource decisions and should be considered in a separate proceeding. Including environmental externalities in the net benefits formula and TRC definition is a major new policy in the rules as proposed and has therefore not received adequate public discussion.

The proposed rules should move forward without including environmental externalities. The Board should convene a separate, broad-based investigation into the applicability of environmental externalities in energy planning for New Jersey, including non-utility generation.

Time differentiated environmental externalities are not necessary because of the highly subjective and uncertain nature of environmental externalities valuation.

The rules should establish $.02/kwh for environmental externalities as the floor and, upon a party's recommendation or upon its own motion, the Board should be allowed to adjust this figure upward.

Several parties commended the Board on the inclusion of environmental externalities although the rules are unclear whether environmental externalities are in today's present value dollars or not.

Among the reasons to pursue energy efficiency and renewables, the lengthy, populated New Jersey coastline will suffer egregiously from sea level rise (greenhouse effect). New Jersey's contribution to the level of CO_2 (carbon dioxide) is small, but because New Jersey imports more than 60 percent of its electricity, which is mostly generated by high sulfur, coal-fired plants, SO_2 (sulfur dioxide) yields acid rain which has effects both in and out of State. Conservation initiatives can help mitigate these problems.

The environmental externalities method used is a reasonable interim method, although the Pace report on environmental externalities used as support in the rules is based on highly speculative methods.

Resources should be compared using actual costs including costs to comply with environmental laws and regulations.

The Board must conduct a full adjudicatory hearing on the subject of externalities and quantification should be attempted only when all interests are represented in the body grappling with this issue.

The monetization values of environmental externalities must be refined before being adopted by any government agency.

Externalities must be analyzed in the context of supply, demand and dispatch.

The Board should address during the new proceeding the utilization of full fuel cycle costs to help level the playing field among fuel sources, by considering, for example, the costs associated with the disposal of the by-products of nuclear generation or with the health impacts of coal mining and cleaning.

The Board should also consider the addition of environmental dispatch to economic dispatch.

Environmental costs should be internalized for all sources, particularly existing utility plants. The proposed rules bias the procurement process by valuing environmental costs only for DSM sources not environmentally beneficial IPP sources. A system of environmental dispatch instead of economic dispatch of utility plants should be considered.

Regarding Environmental Externalities, the use of $.95 per MMBtu for gas utility DSM programs has been questioned as being too high and not adequately accounting for such factors as the market segment consuming the gas and the geographic region in which it is consumed.

There has also been objection to the proposed $.95 per MMBtu estimate for environmental externality savings alleging that the assumption from the 1990 Pace Report is inappropriate because DSM plans will not relate the fuel savings for electricity generation.

The value of $.95 per MMBtu for environmental externality savings is the best estimate available at this time.

It has been also argued that the Environmental Externalities section omits a value for the avoided cost of fuel oil. Furthermore, the use of the Pace Study results which pertain to electricity generation, for natural gas and user applications, is not fully developed.

RESPONSE: The quantification of environmental costs associated with electric generation and natural gas combustion is an evolving endeavor. At least three states, New York, Massachusetts and Nevada, have adopted specific values for environmental externalities for inclusion in least cost planning processes of utilities. The Board referenced a 1990 Report prepared by the Pace University Center for Environmental Legal Studies for the New York State Energy and Developmental Authority and United States Department of Energy, which studied the existing literature valuing environmental costs of electric utility operation. Driven primarily by air pollution costs related to SO_2, NO_x, particulates and CO_2, the report develops environmental costs for coal-fired, natural gas fired and oil-fired generating facilities, among others. It should be noted that the environmental externality values adopted in Nevada and Massachusetts are similar to the figures established in the Pace Reports.

Making the conservative assumption that all coal-fired units from which New Jersey utilities purchase electricity meet the New Source Performance Standards (NSPS) established by the N.J. Department of Environmental Protection and Energy, (which will not be the case for a number of years), and employing a weighted average of New Jersey electric fuel mix (including purchases) of 50 percent coal, 10 percent gas and 10 percent oil, electric generation produces an average air pollution environmental cost of 2.65 cents per kwh. This assumes no environmental cost for nuclear generation. The predominant marginal generating unit technologies appearing in the New Jersey utilities' capacity plans are natural gas-fired combustion turbines or combined cycle units. The Pace Report estimates that the environmental cost of generation from the avoided production plant is more on the order of 1.0 cent per kwh. However, the avoided gas-fired combustion turbine or combined cycle facility would be expected to run from several hundred to several thousand hours per year predominantly during peak and shoulder periods. As a result, baseload energy efficiency DSM measures can be expected to avoid generation from existing plant, likely coal-fired facilities, during off-peak hours.

In consideration of the factors noted, the proposed rules establish an average value for electric environmental externalities of 2.0 cents per kwh. The provision for time differentiation of environmental costs to take into account the previously stated factors is appropriate, in order to recognize the difference in sources of power and related emissions depending on time of day.

For natural gas, the value for environmental externalities is established in the rule at $.95/MMBtu (one million British thermal units), which approximates the environmental costs established in the Pace Report for natural gas combustion at an electric generating facility. As with the electric figures, this value is considered conservative since the gas-fired electric generating unit is assumed to have various emission controls not present at natural gas end user premises.

The Board agrees with the comments in recognizing that the environmental values established in the proposed rules represent merely an approximation, and will likely be the subject of further study and refinement. However, the Board maintains that a starting point should be established for purposes of assessing the benefits of DSM programs. The proposed rules provide for modification of these values, either up or down, in future DSM plan filings as the base of information in this field evolves.

While the Board recognizes that the environmental externality values are imprecise at this time, the Board believes it is appropriate to include some reasonable value rather than to ignore its value as some commenters have suggested.

Finally, N.J.A.C. 14:12-3.8(a)1iii has been added to clarify the Board's original intent that the environmental externalities values are in 199[illegible] dollars and are to be escalated annually at a rate equal to the GNP deflator index.

135. COMMENT: What is timely recovery of program expenses?

RESPONSE: Pursuant to the proposed rules, utilities are free to propose the timing of recovery of program expenses subject to Board approval. The Board anticipates a relationship between the amortization of program costs and program benefits. That is, a program with a sho[illegible] payback and low up-front costs would have a shorter amortization period for program expenses than a program with a longer payback and higher up-front cost.

136. COMMENT: Program cost recovery should be reconciled in the annual levelized energy adjustment clause filing.

RESPONSE: The proposed rules provide utilities with the flexibility to propose program cost recovery concurrent with the levelized energy adjustment clause subject to Board approval.

137. COMMENT: The Board should clarify that no program expenses other than core program expenses are allowed to be recovered in rates.

RESPONSE: N.J.A.C. 14:12-4.1(d) has been added to clarify the expenses that a utility is entitled to recover in rates.

138. COMMENT: The proposed rules should plainly state the Board's policy DSM earnings through shared savings or a standard offer will [illegible] no way contribute to the determination of the authorized rate of return on rate base. Excessive profits would be earned under the proposed rules well in excess of reasonable return normally allowed by the Board. The rules must provide for an excessive earnings cap.

Utilities' overall rate of return should reflect the aggregate risk of supply and demand side investments.

RESPONSE: The Board concurs that DSM earnings should not directly contribute to the determination of the authorized rate of return. Rather, the realized returns on these investments should relate to [illegible] risks incurred. However, the Board believes that the provision of incentives, as well as revenue erosion adjustments, should be monitored within the context of overall earnings and possibly be subjected to an excessive earnings cap.

The addition of an earnings cap would be considered a significant modification to the proposed rules. Due to the Board's desire to implement the rules and facilitate the commencement of program design [illegible] regulatory review, a specific earnings cap will not be added at this time.

EXHIBIT E

Prepared for
NEW YORK STATE ENERGY RESEARCH AND DEVELOPMENT AUTHORITY
Project Manager: David R. Wolcott
&
UNITED STATES DEPARTMENT OF ENERGY

ENVIRONMENTAL COSTS *of* ELECTRICITY

Prepared by
PACE UNIVERSITY CENTER FOR ENVIRONMENTAL LEGAL STUDIES
RICHARD L. OTTINGER • DAVID R. WOOLEY
NICHOLAS A. ROBINSON • DAVID R. HODAS • SUSAN E. BABB

Policy Analysts:
Shepard C. Buchanan: *Environmental Economics Consultant*
Paul L. Chernick • Emily Caverhill: *PLC, Inc.*
Alan Krupnick • Winston Harrington • Seri Radin: *Resources for the Future*
Uwe Fritsche: *OKO-Institut*

THE OCEANA GROUP • PUBLISHERS
1990
OCEANA PUBLICATIONS, INC.
NEW YORK • LONDON • ROME

VI. EXTERNALITY COSTS BY RESOURCE

A. COAL PLANT OPERATIONS

VI. EXTERNALITY COSTS BY RESOURCE

A. COAL PLANT OPERATIONS

1. Table Summary

The major externalities related to air emissions from typical existing and new coal-fired facilities are summarized in Table A. The air emissions reported in this summary are sulfur dioxide (SO_2), nitrogen oxides (NO_x), particulates, and the major greenhouse gas, CO_2. The unit values for each externality are the "starting point" estimates developed in Chapter V. For CO_2 the value used in Table A ($50/ton of carbon) is near the middle of the range of costs described in the studies summarized at the end of Chapter V.A.[1] The emissions for each technology are adapted from Chapter IV and are originally from Chernick and Caverhill (1989) or other sources, as indicated. No scrubber control equipment is used on the example plants for SO_2, NO_x or CO_2 except that a scrubber is assumed for the New Source Performance Standards (NSPS) Plant.[2] However, emissions of SO_2 are dependent on coal sulfur content and, for atmospheric fluidized bed combustion (AFBC), on the amount of limestone used. For particulates, the existing boiler has installed an electrostatic precipitator (ESP) with an efficiency of 90%, and the AFBC and integrated gas combined cycle (IGCC) plants have fabric filters with an efficiency of 98%. The particulate emissions are strongly dependent on the ash and sulfur content of the coal, so the emissions quoted here may be very different under different assumptions.

Table A shows estimates of the externalities from three different coal-fired technologies. The externalities from a coal-fired boiler, with a heat rate of 10,000 BTU/kWh and burning 1.2% sulfur coal, are on the order of 5.8 cents/kWh (generated). For an AFBC plant with the same heat rate and burning 1.1% sulfur coal, the externalities are on the order of 2.8 cents/kWh (generated). For an IGCC plant with the same heat rate and sulfur content of 0.45% sulfur the externalities are on the order of 2.5 cents/kWh (generated).

2. Exclusions

These estimates do not consider overlap between the effects of SO_2 emissions and particulate emissions, particularly the health and visibility effects related to sulfate deposition. However, since the particulate cost estimate excludes the potentially significant health effects of sulfates, and so is based entirely on visibilityeffects, and the SO_2 value is dominated by health effects, we do not anticipate that these effects are double counted.

---

[1] In the table this $50/ton of carbon is converted to 2.5 cents per pound of carbon or .68 cents per carbon dioxide.

[2] The emissions figures are based on a plant that is just meeting the NSPS SO_2 limit.

In addition, these externality estimates leave out so many potential externality effects that they are likely to be conservative rather than overstated. Other externalities should be incorporated into future externalities estimates. These include: air emissions from coal combustion not estimated here, such as the greenhouse gases methane (from coal mining) and N_2O; air toxics including heavy metals; the other primary ozone precursor, VOC; other externalities related to coal combustion, such as water use, land use, and solid waste disposal; and externalities related to the other stages of the coal fuel cycle, including extraction, processing and transportation.[3]

[3] Several of these effects, including air toxics emissions, water use, land use and solid waste disposal, are discussed in this report, but costs could not be estimated from the reports reviewed.

TABLE 1

EXTERNALITYCOST FOR COAL-FIREDUNITS
(Emissions - lbs/MMBTU)

Externality	\$/lb	Existing Boiler (1.2% S)	AFBC (1.1% S)	IGCC (.45% S)	NSPS (N/A)
	[A]	[B]	[C]	[D]	[E]
[1] SO_2	\$ 2.03	1.80	0.55	0.2 ~~0.48~~	1.2
[2] NO_x	\$ 0.82	0.607	0.3	0.06	0.006
[3] Particulates	\$ 1.19	0.15	0.01	0.01	0.03
[4] CO_2	\$ 0.0068	209	209	209	209
Totals:					
[5] \$/MMBTU Input		\$ 5.76	\$ 2.80	\$ 2.46	\$ 3.90
[6] Heat Rate (BTU/kWh)		10,000	10,000	10,000	10,000
[7] \$/kWh Generated		\$ 0.058	\$ 0.028	\$ 0.025	\$ 0.039
[8] \$kWh Delivered		\$ 0.068	\$ 0.033	\$ 0.028	\$ 0.045

Notes:

[A]: Unit Values derived in Chapter V.
[B][C][D][E]: Emissions are from PLC (1989); SO_2 and CO_2 emissions have been restated as lbs SO_2 and lbs CO_2. All emissions are expressed as lbs/MMBTU fuel input.
[E]: NSPS regulations require 1.2 lbs/MMBTU and 90% reduction for plants with emissions greater than 0.6 lb/MMBTU; for plants with emissions less than 0.6 lb/MMBTU; NSPS requires 70% reduction in emissions.
[1]: No SO_2 scrubbers are installed on the first three plants.
[2]: NO_x emissions are uncontrolled in each case.
[3]: Particulates emissions vary widely and are extremely dependent on the ash content and sulfur content and sulfur content of the coal. NSPS requires 0.03 lbs/MMBTU and 90% reduction.
[4]: CO_2 emissions are derived in PLC (1989).
[5]: Sum of (value x emissions for each externality) for each plant.
[6]: Assumed heat rates for each plant.
[7]: [5] x [6]/1,000,000.
[8]: Assumes 15% marginal energy losses.

VI. EXTERNALITY COSTS BY RESOURCE

B. OIL PLANT OPERATIONS

VI. EXTERNALITY COSTS BY RESOURCE

B. OIL PLANT OPERATIONS

1. Table Summary

The major externalities related to air emissions from existing and new oil-fired combustion facilities are summarized in Table B. The air emissions reported in this summary are sulfur dioxide (SO_2), nitrogen oxides (NO_x), particulates, and the major greenhouse gas, (CO_2). The unit values for each externality are the "starting point" estimates developed in Chapter V. The emissions for each technology are adapted from Chapter IV and are originally from Chernick and Caverhill (1989) or other sources, as indicated. No pollution control equipment is used on any of the example plants for SO_2, NO_x or CO_2. However, the SO_2 emissions are dependent on the sulfur content of the oil. For particulates, the emissions are dependent on the sulfur content of the fuel, and are calculated using the formula noted, which is taken from EPA AP-42.[1]

Table B shows estimates of the externalities from two different oil-fired technologies: boilers burning residual, or #6, oil and a combustion turbine burning distillate, or #2, oil. For the boilers, three different sulfur contents are assumed, but each boiler has a heat rate of 10,400 BTU/kWh. The externalities from the #6 oil-fired boiler burning 0.5% sulfur oil are on the order of 2.7 cents/kWh (generated). For the same boiler burning 1% sulfur oil the externalities are 3.8 cents/kWh (generated), and for the same boiler burning 2.2% sulfur oil the externalities are 6.7 cents/kWh (generated). The externalities of the combustion turbine burning distillate or #2 oil, with a heat rate of 13,600 BTU/kWh, are on the order of 2.5 cents/kWh (generated) assuming 1% sulfur.

2. Exclusions

As in the case of coal fired plant these cost estimates do not consider overlap between the effects of SO_2 emissions and particulate emissions, particularly the health and visibility effects related to sulfate deposition. However, since the particulate cost estimate excludes the potentially significant health effects of sulfates, and so is based entirely on visibility effects, and the SO_2 value is dominated by health effects, we do not anticipate that these effects are double counted.

In addition, these externality estimates leave out so many potential external effects that they are likely to be conservation rather than overstated. Other externalities should be incorporated into future externalities estimates. These include: air emissions from oil combustion not estimated here, such as the greenhouse gases methane (from oil drilling and production) and N_2O: air toxics including heavy metals:

---

[1] EPA AP-42, Compilation of Air Pollutant Emission Factors, Volume I: Stationary Point and Area Sources, Fourth Edition, September 1985 (updated 10/86).

the other primary ozone precursor, VOC; other externalities related to oil combustion, such as water use, land use, and solid waste disposal; and externalities related to the other stages of the oil fuel cycle, including extraction, refining and transportation.[2]

[2] Several of these effects, including water use, land use and solid waste disposal, are discussed in this report, but costs could not be estimated from the reports reviewed.

TABLE 1

EXTERNALITYCOST FOR OIL-FIRED UNITS
(Emissions - lbs/MMBTU)

Externality	$/lb	Boiler # 6 Oil (.5% S)	Boiler # 6 Oil (1% S)	Boiler # 6 Oil (2.2% S)	Combustion Turbine # 2 Oil (1% S)
	[A]	[B]	[C]	[D]	[E]
[1] SO_2	$ 2.03	0.54	1.08	2.38	0.16
[2] NO_x	$ 0.82	0.357	0.287	0.357	0.498
[3] Particulates	$ 1.19	0.055	0.09	0.174	0.036
[4] CO_2	$ 0.0068	169	169	169	161
Totals:					
[5] $/MMBTU Input		$ 2.60	$ 3.68	$ 6.48	$ 1.87
[6] Heat Rate (BTU/kWh)		10,400	10,400	10,400	13,600
[7] $/kWh Generated		$ 0.027	$ 0.038	$ 0.067	$ 0.025
[8] $kWh Delivered		$ 0.032	$ 0.045	$ 0.079	$ 0.030

Notes:

[A]: Unit Values derived in Chapter V.
[B][C][D][E]: Emissions are from PLC (1989); SO_2 and CO_2 emissions have been restated as lbs SO_2 and lbs CO_2. All emissions are expressed as lbs/MMBTU fuel input.
[1]: SO_2 emissions are uncontrolled in each case.
[2]: NO_x emissions are uncontrolled in each case.
[3]: Particulates emissions are calculated from EPA Ap-42 using the formula: 0.02 + 0.07 x S, where S ia the sulfur content in percent.
[4]: CO_2 emissions are derived in PLC (1989).
[5]: Sum of (value x emissions for each externality) for each plant.
[6]: Assumed heat rates for each plant.
[7]: [5]*[6]/1,000,000.
[8]: Assumes 15% marginal energy losses.

VI. EXTERNALITY COSTS BY RESOURCE

C. NATURAL GAS PLANT OPERATIONS

VI. EXTERNALITY COSTS BY RESOURCE

C. NATURAL GAS PLANT OPERATIONS

1. Table Summary

The major externalities related to air emissions from existing and new natural gas combustion facilities are summarized in Table C. The air emissions reported in this summary are sulfur dioxide (SO_2), nitrogen oxides (NO_x), particulates, and the major greenhouse gas, CO_2. The unit values for each externality are the "starting point" estimates developed in Chapter V. The emissions for each technology are adapted from Chapter IV and are originally from Chernick and Caverhill (1989) or other sources, as indicated. No special NO_x-control equipment is used on the boiler or the combined cycle. However, selective catalytic reduction (SCR) and steam water injection (SWI) are applied on the BACT unit, which is a combined cycle unit fitted with best available control technology. SO_2 emissions from natural gas combustion are negligible.

Table C shows estimates of the externalities from two different natural gas-fired technologies: boilers (steam plants) and combined cycle. For the combined cycle plant, two different plants are illustrated: a plant with no add-on controls, and a plant with the best available control technology for NO_x and particulate control. The externalities from the natural gas-fired steam plant, with a heat rate of 10,400 BTU/kWh, are on the order of 1.0 cents/kWh (generated). For the combined cycle unit, with a heat rate of 9,000BTU/kWh, externalities are estimated to be on the order of 1.0 cents/kWh (generated) also. For the combined cycle unit fitted with SCR and SWI, the externalities drop to 0.7 cents/kWh (generated). The externality values estimated for natural gas units are strongly dominated by the CO_2 emissions, which vary only with the heat rates of the different plants.

2. Exclusions

These externality estimates are likely to be conservative because of the external effects that are not included. Other potentially important natural gas combustion externalities should be incorporated into future externalities estimates. These include other air emissions, such as the greenhouse gases, methane from production and pipeline losses and N_2O; the other major ozone precursor, VOC; other externalities related to gas combustion, such as water use and land use; and externalities related to the other stages of the natural gas fuel cycle including extraction and transportation.[1]

[1] Several of these effects, including water use and land use, are discussed in this report, but costs could not be estimated from the reports reviewed.

TABLE 1

EXTERNALITYCOST FOR NATURALGAS-FIRED UNITS
(Emissions - lbs/MMBTU)

Externality	$/lb	Existing Steam Plant	Combined Cycle	BACT (SCR, SWI)
	[A]	[B]	[C]	[D]
[1] SO_2	$ 2.03	0	0	0
[2] NO_x	$ 0.82	0.248	0.42	0.042
[3] Particulates	$ 1.19	0.003	0.003	0.0002
[4] CO_2	$ 0.0068	110	110	110
Totals:				
[5] $/MMBTU Input		$ 0.95	$ 1.10	$ 0.78
[6] Heat Rate (BTU/kWh)		10,400	9,000	9,000
[7] $/kWh Generated		$ 0.010	$ 0.010	$ 0.007
[8] $kWh Delivered		$ 0.012	$ 0.011	$ 0.008

Notes:

[A]: Unit Values derived in Chapter V.
[B][C][D]: Emissions are from PLC (1989); SO_2 and CO_2 emissions have been restated as lbs SO_2 and lbs CO_2. All emissions are expressed as lbs/MMBTU fuel input.
[1]: SO_2 emissions are zero from gas combustion.
[2]: NO_x emissions are uncontrolled in the first two cases; For the BACT case, Selective Catalytic Reduction and Steam Water injection are assumed.
[3]: Particulates emissions are estimated for CEC (1989). BACT assumes fabric filter control.
[4]: CO_2 emissions are derived in PLC (1989).
[5]: Sum of (value x emissions for each externality) for each plant.
[6]: Assumed heat rates for each plant.
[7]: [5]*[6]/1,000,000.
[8]: Assumes 15% marginal energy losses.

EXHIBIT F

RECYCLED

EXHIBIT F

RECYCLED

Prepared for

NEW YORK STATE ENERGY RESEARCH AND DEVELOPMENT AUTHORITY
Project Manager: David R. Wolcott
&
UNITED STATES DEPARTMENT OF ENERGY

ENVIRONMENTAL COSTS *of* ELECTRICITY

Prepared by

PACE UNIVERSITY CENTER FOR ENVIRONMENTAL LEGAL STUDIES
RICHARD L. OTTINGER • DAVID R. WOOLEY
NICHOLAS A. ROBINSON • DAVID R. HODAS • SUSAN E. BABB

Policy Analysts:
Shepard C. Buchanan: *Environmental Economics Consultant*
Paul L. Chernick • Emily Caverhill: *PLC, Inc.*
Alan Krupnick • Winston Harrington • Seri Radin: *Resources for the Future*
Uwe Fritsche: *OKO-Institut*

THE OCEANA GROUP • PUBLISHERS •

1990
OCEANA PUBLICATIONS, INC.
NEW YORK • LONDON • ROME

combining the emissions described in Chapter IV with the cost data from the literature reviewed in Chapter V.

Chapter VII evaluates existing models that could be adapted for calculating environmental externality costs, together with the elements and requirements for an ideal model.

Chapter VIII provides a spreadsheet available on computer software (Lotus 1-2-3). Typical spreadsheet runs are provided demonstrating environmental costing at a typical power plant, showing how changes in variables such as fuel changes, pollution controls, populations exposed, discount rates and other factors affect environmental costs.

Research needs are addressed, in Chapter IX. Many areas where little or no research has been done are important when determining environmental costs. These include, for example, valuing the risks of nuclear proliferation and the psychological effects of living near a nuclear plant or coal facility. There are also areas where existing studies are inadequate. The report seeks to identify, in many of the sections, the areas in which research is most needed, and to pull these findings together in Chapter IX.

State and federal actions to incorporate externality costs in utility planning and resource acquisition procedures are described in Chapter X. Section G of this Chapter gives a "State-by-State Survey of Environmental Cost Treatment." The different methodologies, used and proposed, that are available to utilities and regulatory commissions for incorporation of environmental costs are described. In-depth coverage is given to treatment by the states that have been most active in incorporating environmental costs.

Chapter X analyzes alternatives for treatment of environmental externalities. Pollution fees or taxes, subsidies and combinations of state statutory and regulatory methodologies are analyzed and discussed. Tables at the end of Section D of this chapter graphically portray the methodologies that have been used by each state.

Chapter XI provides an overall conclusion to the entire report.

Chapter XII provides a glossary of the technical terms used in the report, and in Chapter XIII provides a partially annotated bibliography of the sources reviewed is presented. There are also bibliographic references given at the end of individual chapters.

Appendix A contains sample runs on TEMIS computer software for computing environmental damages, developed by Uwe Fritsche of OKO-Institut in Darmstadt, Federal Republic of Germany.

C. REPORT RESPONSIBILITIES

Pace University's Center for Environmental Legal Studies is ultimately responsible for the contents of the report. We could not have done it without the hard work of our students who did initial research for most sections of the report. Their lack of economic or utility regulation backgrounds was compensated for by expert consultant help from PLC, Inc., Shepard Buchanan, an environmental economics consultant, and Alan Krupnick and his associates at Resources for the Future (RFF).

Pace University Law School students did the initial research and drafts of the following sections: Brian T. Henderberg and Stephen C. Hughes, the Nuclear Costing section; Michelle L. Fields and Todd Masterman, Particulates; Berkeley Johnson and David Prior, Emissions; Carol Conyers, Acid Rain & SO_2; David R. Everett, Ozone & NO_x; Dina Berger, Solar; Rosalie Rusinko, Carol Padron and Elizabeth Barbanes, Bibliography. Fred Koelsch did editorial work on a number of sections including Hydro costs; Michael E. Waller, was clean-up batter.

The following students helped in revising the report: Karl R. Rabago contributed an able LL.M. thesis on environmental impacts on aquatic ecosystems of cooling water intake systems and drafted the water impacts and fish impingement subsections of the Land and Water section. Terzah N. Lewis, Paul Schmidt, Christopher King, Melanie Fund-Pien, Kevin Desharnais, Eric Blaha and Rosemarie Bria did follow-up research and provided editorial assistance in preparation of the final report.

David R. Hodas, currently a professor at Widener University School of Law and Senior Fellow of the Pace University Center for Environmental Legal Studies, wrote and edited the global warming section as his Pace LL.M. thesis, and then helped edit the entire report. Judy Oken Hodas provided extremely valuable editorial assistance on crucial portions of the Report. Dean Anthony J. Santoro's very generous support of their work is appreciated. Mary Spinelli did the reams of retyping.

A former Pace Center staff member, Susan E. Babb, drafted the fossil fuel emissions tables, the solid waste discussion in the land and water costing section (V.F.), the initial renewable energy draft and parts of the incorporation section. She also organized and wrote much of the bibliography, and supervised the students during the first year of the study.

David R. Wooley, appointed Executive Director of the Center in January, 1990, authored the waste to energy and DSM sections, wrote large parts of the renewables, land and water, research needs and emissions portions of the report. He also edited the final draft and supervised the students during the final seven months of the study.

Richard L. Ottinger, director of the study, edited all contributions, wrote this introduction, the executive summary, except for the resource costing section, and with Babb, the incorporation section.

Shepard Buchanan, the subcontractor was designated in our NYSERDA and DOE contracts, was responsible for the Analytical Framework, Evaluation of Models, Spreadsheet and Glossary sections of the report.

Paul Chernick, President of PLC, Inc. and PLC Research Associate, Emily Caverhill, took on the enormous task of rewriting and revising all the other pollution costing sections. Without their invaluable contributions, this report would not have been produced with anything like the quality presented.

PLC wrote the coal, oil and natural gas costing sections of the report and the executive summary section on resource costing, took the lead on Research Needs, rewrote the SO_2, NO_x/Ozone, Particulates and Nuclear sections, and edited the Global Warming section.

Alan Krupnick and Winston Harrington of Resources for the Future (RFF), with Sari Radin, rewrote the Acid Rain chapter.

Uwe Fritsche of the OKO Institut, Darmstadt, FRG, contributed Appendix A, giving a sample run of his TEMIS software for calculating environmental externalities for a typical U.S. coal-fired electric utility generating plant.

Buchanan, Chernick and Krupnick; Professor Nicholas A. Robinson, Co-Director of the Pace Center and a member of the Pace Law School faculty; David Hodas; and Uwe Fritsche all participated in editing and gave helpful comments on sections for which they were not directly responsible. As mentioned, Judy Oken Hodas did the over-all editing of the report. Pace did the final editing on all contributions.

* * * * *

As can be seen from the above, this report has many authors, and it is not surprising, given such a controversial subject, they sometimes represented quite different points of view. Buchanan and Krupnick are economists, Chernick is a utility specialist, Ottinger is an energy and utility expert, Wooley an attorney and air pollution specialist and Hodas an environmental professor.

These differences are sometimes reflected in this report. Thus, with respect to discount rates, Chernick prefers a utility discount rate, Buchanan a social rate of time preference, while Ottinger, Wooley and Hodas would opt for a zero discount rate in valuing environmental externalities. Chernick is much more inclined to use control or mitigation costs than the other authors, particularly Krupnick who feels they should not be used at all. The other authors agree, however, that control costs should be used where damage values are not ascertainable. Krupnick is far more cautious about using past pollution damages to value marginal damages than are the other authors and is less willing to use studies from one part of the country or the world to extrapolate estimates of future damages generically. The acid rain section, authored by Krupnick and his associates, reflects this conservatism about both the scientific ability to predict damages and the ability to value damages, which makes this section quite different from the other sections of the report. For example, note the different treatment of material damages from acid deposition in Chapter V.D. and from SO_2 in Chapter V.B.

All the authors agree, however, that seeking to value damages is vitally important and that this report presents valuable data that can be used to make more definitive damage determinations in the future.

D. ACKNOWLEDGMENTS

We are very grateful to NYSERDA and DOE for giving us the opportunity to do this work, and particularly to our Contract Manager, David R. Wolcott, of NYSERDA for his invaluable help, advice, and patience; and Laurence B. DeWitt, formerly Director of Conservation and Renewables at NYSERDA, and now staff director in those areas for the PSC, who proposed the project and ushered it through NYSERDA. At the U.S. Department of Energy we wish to thank John Millhone, Director and John

XV. APPENDIX B

5. Bibliography for Chapters V. B, C, AND E

Berrett, L. and T. Weddell, Costs of Air Pollution Damage: A Status Report, Environmental Protection Agency, National Environmental Research Center, Research Triangle Park, North Carolina, February 1973, p. 59.

Birkhofer, A., Was Leisten Risikostudien?, atomwirtshaft-atomechnik, vol. 31, 1986.

Bromberg, P., Testimony before the House Subcommittee on Environmental Protection, Energy and Commerce Committee hearing on Health Effects of Air Pollution, Washington D.C., 1989.

Brookshire, D., Methods Development for Valuing Hazards Information, Institute for Policy Research, 1980.

Bureau of National Affairs, "DOE Releases State, Regional Guidance on Compliance with Low Level Waste Act," vol. 10., no. 24, October 8, 1987, p. 1516.

Cadle, R., "Particulate Matter in the Lower Stratosphere," Chemistry of the Lower Stratosphere, NY, Plenum Press, 1973.

California State University Fullerton Foundation, Economic Assessment of the Health Benefits from Improvements in Air Quality in the South Coast Air Basin, Prepared for the South Coast Air Quality Management District Contract No. 5685, Fullerton, Calif., June 1989.

Cannon, J., The Health Costs of Air Pollution: A Survey of Studies Published 1978-1983, American Lung Association, August 1985, pp. 12-14.

_____, The Health Costs of Air Pollution: A Survey of Studies Published 1984-1989, American Lung Association, 1990.

Charles River Associates (CRA), Benefits and costs of Externalities and Intangibles Associated with Southern California Edison's 1985 and 1986 Conservation and Load Management Programs, CRA Report #792, May 15, 1984.

Chernick, P. and Caverhill, E., The Valuation of Externalities from Energy Production, Delivery, and Use, Boston, MA, PLC, Inc., December, 1989.

_____, The Valuation of Externalities from Energy Production, PLC, Inc., Boston, MA, December 1989.

Chernick, P., W. Fairley, M. Meyer, and L. Scharff, 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., and J. Wallach, Testimony on Behalf of the Massachusetts Executive Office of Energy Resources, MDPU 89-100, June 30, 1989.

EXHIBIT G

RECYCLED

Figure 1: Mercury Externalities @ $2,500 per pound of Mercury Emitted

Plant	Emissions [a] (lbs/10^12Btu)	Heat Rate [b] (MMBtu/MWh)	Emissions [c] (lbs/MWh)	Cost [d] $/MWh	Annual Output [e] (MWh/year)	Annual Cost [f] $/Year
Freehold (oil)	3.0	7.992	2.40E-05	$0.060	60,000	$3,596
Keystone	5.0	9.643	4.83E-05	$0.121	912,500	$110,198
Crown Vista	10.7	9.750	1.05E-04	$0.262	912,500	$238,709
Generic Coal	16.0	11.000	1.76E-04	$0.440	912,500	$401,500

Notes:

[a]: Freehold and generic coal mercury emissions are from EPA (1989).
Keystone emissions = [0.0106 lbs/hr (max)] / [2,116 MMBtu/hr (max)] *10^6. [Source: Air Quality Permit.]
Crown Vista emissions = [0.0192 lbs/hr (max)] x [1,789 MMBtu/hr (max)] x 10^6. [Source: Air Quality Permit.]
[b]: Heat rates provided by Freehold Cogeneration, Inc.
[c]: Lbs/MWh = (lbs/10^12 MMBtu) x (MMBtu/MWh) / (10^6)
[d]: $/MWh = (lbs/MWh) x $2,500/lb
[e]: MWh/Year = 125 MW x 480 hrs/yr for Freehold burning oil, and 125 MW x 7,300 hrs/yr for the coal plants.
[f]: $/Year = ($/MWh) x MWh/year