STATE OF ILLINOIS

ILLINOIS COMMERCE COMMISSION

Illinois Commerce Commission On Its Own Motion	))	
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Proceeding to adopt an electric energy plan for Commonwealth Edison Company.	))	

DIRECT TESTIMONY OF PAUL L. CHERNICK

ON BEHALF OF THE CITY OF CHICAGO

(CITY EXHIBIT 2.0)

FEBRUARY 1, 1994

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I. Identification and Qualifications

Q: Mr. Chernick, please state your name, occupation, and business address.

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

Q: Summarize your professional education and experience.

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

I was a Utility Analyst for the Massachusetts Attorney General for over three years, and was involved in numerous aspects of utility rate design, costing, load forecasting, and the evaluation of power supply options. Since 1981, I have been a consultant in utility regulation and planning, first as a Research Associate at Analysis and Inference, after 1986 as President of PLC, Inc., and since August 1990 in my current position at Resource Insight. In those capacities, I have advised a variety of clients on utility matters, including, among other things, the need for, cost of, and cost-effectiveness of prospective new generation plants and transmission lines; retrospective review of generation planning decisions; ratemaking for plant under construction; ratemaking for excess and/or uneconomical plant entering service; conservation program design; cost recovery for utility efficiency programs; and the valuation of environmental externalities from energy production and use. My resume is attached as Exhibit PLC-1.

Q: Have you testified previously in utility proceedings?

A: Yes. I have testified over one hundred 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 Texas Public Utilities Commission, the New Mexico Public Service Commission, the District of Columbia Public Service Commission, the New Hampshire Public Utilities Commission, the Connecticut Department of Public Utility Control, the Michigan Public Service Commission, the Maine Public Utilities Commission, the Minnesota Public Utilities Commission, the South Carolina Public Service Commission, the Federal Energy Regulatory Commission, and the Atomic Safety and Licensing Board of the U.S. Nuclear Regulatory Commission. A detailed list of my previous testimony is contained in my resume.

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

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

Q: Have you testified previously before this Commission?

A: Yes. I testified before the Illinois Commerce Commission in ICC Docket No.

82-0026, concerning the cost-effectiveness of construction of the Braidwood nuclear power plant, and in ICC Docket No. 90-0038, concerning the 1990 Least Cost Plan of Commonwealth Edison Company.

Q: On whose behalf are you testifying?

A: My testimony is being sponsored by the City of Chicago.

II. Introduction

Q: What is the purpose of your testimony?

A: The purpose of this testimony is to review the Least Cost Plan (the "Plan") of Commonwealth Edison (CWE or Edison). My review concentrates on CWE's treatment of Demand Side Management (DSM) and existing supply resources in DSM screening, avoided cost estimation, and integration analysis.

Q: Please summarize your testimony.

A: CWE has failed to demonstrate that it has developed a truly least-cost plan, for the following reasons:

- CWE's DSM screening process biases its planning against the selection of cost-effective DSM;
- CWE underestimates the costs avoided by DSM, further biasing planning against cost-effective DSM;
- CWE's Plan is based on an unrealistic and unsupported forecast of the future cost, capacity and performance of its existing supply resources; and
- The documentation provided by CWE appears insufficient to demonstrate that CWE's Plan is least cost.

Q: Why are avoided costs important in least-cost planning?

A: For several types of resources, the level of avoided costs will determine the amount of the resource that appears to be cost-effective for inclusion in the least-cost plan. For example, understating costs avoided by demand-side management programs would lead CWE to undervalue demand-side resources, and thus to underinvest in them. Such under-investment in DSM inevitably leads to excessive expenditures on more expensive supply resources. Similarly, understating one component of avoided costs (such as energy costs) would result in underutilization of some resources (such as conservation) and the uneconomic over-investment in other resources (such as load management and baseload supply resources).

Valuation of DSM affects not only the level of DSM that is cost-effective, but also customer eligibility for DSM services and, hence, the distribution of DSM benefits across customer classes. Under CWE's avoided costs, many commercial and industrial DSM options were found to be cost-effective, but few residential options passed screening.

Q: Would accurate valuation of DSM ensure proper treatment of DSM in CWE's resource planning?

A: Not by itself. CWE's approach to DSM selection deviates from sound least-cost planning, in at least three ways. First, CWE rejects or delays programs that it has found to be cost-effective under a range of tests.[1] Even for cost-effective programs, CWE proposes to limit its DSM to pilot program and case study activities until 1996.[2] CWE apparently believes that regardless of cost-

[1]This range of tests would include the Utility Cost Test (UCT, which is equivalent to the present value of revenue requirements, or PVRR), the Total Resource Cost (TRC) test, and the Societal test, under a range of discount rates and despite overstatement of costs and understatement of benefits, as discussed below. While I believe the societal or, the TRC equivalently (except without externalities), test should be the basis for screening DSM, this criticism applies under all total cost tests.

[2]According to John C. Bukovski of December 2, 1993, there has been a decline in CWE's peak load forecast since the 1993 Supplement was filed. CWE regards the lower forecast as justification for further delay in the full-scale implementation of DSM:

> The effect of this adjustment [in the load forecast] would be to delay the implementation dates for the resources identified in the 1993 Plan Supplement by approximately one year, and extend the time period over which DSM capability building programs could be implemented.

effectiveness and lost opportunities, full-scale implementation should not occur until the first year of resource deficiency, and before then, DSM should be limited to capability-building (1992 LCP, Main report, p. I-3; Letter from John C. Bukovski (CWE) to Parties, December 2, 1993). In essence, CWE takes the position that the need for capacity, rather than providing least-cost energy services to customers, should determine the timing of DSM expenditures.

Second, CWE rejected DSM options outside the avoided-cost screening process. In its 1992 Plan, CWE eliminated 81 out of 144 DSM technologies based on their load shape effects without regard to cost-effectiveness (1992 Main Report, p. IV-76). For its 1993 plan supplement, CWE eliminated six programs (including residential Compact Fluorescent Bulb, New Home Construction, House Weatherization Retrofit programs), that met load shape objectives in 1992, giving no reason other than that the "program designs require further conceptual development." It is not clear why CWE, working on DSM since about 1985, could not develop program concepts in enough detail to permit screening. Many much smaller utilities have designed and implemented such programs.

Third, CWE understates the TRC benefit-cost ratios of C/I programs by inappropriately including tax effects.

III. Avoided Costs

Q: What DSM benefits should be reflected in avoided cost calculations?

A: CWE should capture the avoidable costs of

- generating capacity, both costs related to peak demand and costs related to energy needs;
- transmission capacity;
- distribution capacity;
- fuel and other variable O&M;
- compliance with environmental regulations;
- line losses in the transmission and distribution system;
- supply risk, and;

- externalities.

While I believe that externalities and the risk mitigation benefits of DSM should be included in avoided costs, I have not addressed these two issues in my testimony.

Q: What basic problems have you identified in CWE's avoided cost analysis?

A: First, there is a category of unsupported and unreasonable assumptions that affect the forecast of the capacity and performance of existing supply resources. In particular:

- CWE assumes that life extension expenditures will result in continued operation of fossil steam plants, generally at improved efficiency and reliability, without adequately demonstrating that the expenditures will be cost-effective;

- CWE does not adequately consider the effect of NOx control requirements on the life extension and performance of existing fossil units; and

- CWE assumes continued operation of all existing nuclear plants, despite the need for major capital additions (in particular, for Zion 1), without adequately demonstrating that continued operation will be cost-effective.

The broadest category of problems stems from a serious lack of documentation that prevents review of the crucial assumptions and methodologies that underlie CWE's Plan. For example:

- CWE fails to document its assessment of the fossil optimization program, even though the Company relies on the study to justify a forecast of continued fossil steam unit operation throughout the planning period.

- The 1993 Supplement reports significant reductions in Edison's "incremental cost" of coal as a result of supply and transportation contract renegotiations. However, CWE has failed to supply the information necessary to determine whether the coal price forecast used in the avoided cost and integration analyses is consistent with the revisions to the coal contracts.

- CWE has not adequately documented its consideration of SO_2 compliance costs in avoided costs and integration analysis. As a result, it is not possible to determine to what extent SO_2 compliance costs were taken into account in CWE's analysis.

- CWE has not even specified the avoided costs it used in screening DSM, let alone the assumptions and calculations on which they are based (CWE responses to JDR-52, 63).

#P Second, there are important benefits of DSM that CWE has completely overlooked, namely:

- avoided distribution costs; and
- effect on opportunities for profitable off-system sales.

Without adequate documentation, the Commission cannot evaluate and approve CWE's Plan.

move up to * on page 6

A. **Life Extension Of Existing Units**

Q: Should life extension expenditures be considered in least-cost planning?

A: Yes. Whether life extensions are treated as avoidable or not, they are of crucial importance in least cost planning. Life extension expenditures affect the capacity and performance of the utility's future supply. The Commission cannot evaluate CWE's supply or demand resources plans without a reasonable, well-supported forecast of the future availability of the existing supply.

1. **Fossil Unit Lives**

Q: How does CWE treat existing fossil steam capacity in the avoided cost and integration analyses?

A: CWE forecasts that all currently operating fossil steam plants will continue to operate throughout the planning period, generally at improved operating efficiency and reliability without any increase in routine O&M costs (CWE response to JDR-62, 1992 Main Report, p. VI-42, 1993 Supplement Summary Report, p. VI.S-3).[3]

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[3]The one exception is Waukegan 6, which is assumed to be retired in 2012.

Q: Does CWE have adequate support for forecasting continued operation of all existing fossil steam units?

A: No. CWE's forecast of continued operation of existing fossil steam units relies on substantial investments in life extension. CWE currently projects that this fossil optimization program (FOP) will cost $855 million. Despite the magnitude of this investment, CWE has not demonstrated that these expenditures are cost-effective and that continued operation of all units is economically feasible. CWE does not appear to have evaluated the cost-effectiveness of the individual unit life extensions.

In addition to CWE's failure to properly consider the cost-effectiveness of life extension, the Plan fails to consider whether the FOP expenditures are deferrable or affected by other resources added in the Plan. Life extension is treated as an all-or-nothing, now-or-never, once-and-forever decision. None of these analytical restrictions is reasonable: some units can be life-extended immediately, life extension of others can be deferred, some units can simply be retired, and the entire plan can be revised to reflect changes in load forecasts, DSM, or other supply resources.

CWE takes the position that there was no need to consider the fossil optimization expenditures in the 1993 integration analysis, because the FOP had already been shown to be economically justified (CWE response to JDR-82). CWE is incorrect. Even if CWE had shown the FOP to be cost-effective in the base case, the exclusion of life extension investments from the integration process apparently results in CWE failing to examine whether the investments would also be cost-effective with lower load growth.

Q: What is the basis for CWE's claim that its fossil optimization program is cost-effective?

A: CWE claims to have recently prepared an assessment of the fossil optimization program, concluding that the Edison "can maintain serviceability for at least the next 10 years at an average cost of less than $100/Kw, which includes required environmental modifications" (1993 Supplement, Summary Report, p. III.S-4). CWE's current estimate of life extension costs is a decrease from the $130/Kw estimated in the 1992 LCP.

CWE has not actually prepared a cost-effectiveness analysis based on the revised project cost estimate, for the 1993 Supplement. Instead, CWE relies on a 1992 analysis that, according to CWE, demonstrated the FOP to be cost-effective. CWE contends that an up-to-date study would show the FOP to have even greater net benefits than previously estimated, because CWE has reduced the total cost estimate (CWE response to JDR-82).

Q: Was CWE's 1992 cost-effectiveness analysis a valid analysis?

A: No. The fundamental flaw in Edison's approach was its assumption that an average cost per Kw for the system can be applied uniformly across all units. In effect, Edison assumed that *all* units could be maintained at the same low average cost, which was less than the cost of a new combustion turbine and well below the cost of providing comparable power from new sources. As a result, CWE's cost-effectiveness analysis ignores the cost and benefit variation among units, which can be substantial. Some units may require only minor retrofits and modest O&M to keep running; if these unit are large and efficient, the life extension is likely to be cost-effective. For other units, the capital and operating cost may be so high, and the benefits so low, that life extension is not cost-effective.[4]

CWE's analysis assumes that the only choice is between (1) life extension for all units and (2) no fossil optimization investments. CWE overlooks completely two additional options: (3) life extension of units that are worth retaining, and retirement of units for which life extension is not cost-effective; and (4) deferral of life extensions.

Without unit-specific life-extension costs and unit-specific cost-

[4]Edison seems to understand this point for DSM: non-cost-effective DSM options should not be bundled with cost-effective options, even if the resulting mix reduces costs as a package. CWE seems reluctant to apply the same logic to life extensions.

effectiveness evaluations, it is not possible for the Commission to determine which units would be too expensive to life-extend, but some generalizations can be drawn from available information. Table ~~5~~ 4 lists CWE's fossil steam units, and information relevant to the life-extension decision. The five cyclone coal units (1,026 MW) in the Chicago ozone non-attainment area are particularly likely candidates for retirement. These are some of the oldest and smallest steam units. More critically, cyclone boilers have high Nox emissions that are likely to require costly control retrofits under Phase 2 of Title I of the Clean Air Act. Other units vulnerable to high-cost retrofits, if not retirement, are the smaller, older non-cyclone boilers in the Chicago non-attainment area (Crawford, Joliet 6, Fisk, Waukegan, State Line) and the large cyclones (Kincaid and Powerton).

Q: Is CWE correct that a reduction in the average cost estimate from 1992 to 1993 will necessarily increase the cost-effectiveness of the fossil optimization expenditures?

A: No, for two reasons. First, the costs for certain units may increase even though the average cost overall declines. Second, since CWE's avoided costs have changed, it is not clear that the 1992 results can be extrapolated to 1993.[5]

Q: Has CWE developed realistic projections of life extension costs and on a unit-by-unit basis?

A: Apparently not. According to CWE, the focus of the fossil optimization assessment was the identification of the retrofits necessary to achieve a target equivalent forced outage rate (EFOR) for each unit, and the study does appear to contain some unit-specific cost estimates. However, from the very limited

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[5]For example, under 1992 conditions, an efficient cyclone unit like State Line 2 might be cost-effective despite high life-extension costs. With lower coal costs, a 1993 analysis might find that life extension of State Line 2 was no longer cost-effective.

information available,[6] CWE apparently has not developed comprehensive unit-by-unit project plans and costs;

- For retrofits aimed at improving unit availability, CWE characterizes its identification of unit-by-unit projects as only "preliminary" and provides only a list of "typical" projects, rather than a detailed unit-by-unit list;[7] and

- CWE does not appear to have included sufficient Nox control costs in its fossil optimization assessment, particularly in the case of the cyclone boilers.

Q: What are the potential Nox control requirements for cyclone boilers?

A: Cyclone boilers have been exempted (in Illinois and elsewhere) from Title IV requirements to install low-NO_x burners, and from Phase 1 of Title I requirements, due to the absence of low-cost control options. But they are likely to be subject to costly controls, depending on the NO_x reductions required by the State Implementation Plan (SIP) to comply with Phase 2 of Title I. The Chicago non-attainment area ~~, consists~~ includes of the following counties (listed with the CWE fossil steam plants located in the county):

- Cook (Crawford, Fisk),
- Lake (Waukegan),
- Will (Joliet, Will County),
- DuPage,
- McHenry,

[6] CWE is unwilling to make any unit-specific or project-specific data available (CWE response to JDR-83). CWE claims that revealing data on life extension cost estimates would allow contractors to somehow rig their bids. Assuming that the potential bidders are not actively colluding, they would be bidding against one another, not CWE's estimates.

[7] CWE claims that the unit-by-unit project lists are confidential. Even if project cost *estimates* were considered confidential, listing *projects* can hardly bias the bidding process. Surely bidders must be told what project they are bidding on.

- Kane,
- Grundy (Collins),
- Kendall, and
- Kankakee,

Not ¶ ~~The non-attainment area also includes~~ as well as neighboring portions of Indiana (including the State Line plant) and Wisconsin, It has ~~is an ozone non-attainment area,~~ ~~with~~ a n ozone design value ~~rating~~ of 223 ppb, compared to the National Ambient Air Quality Standard (NAAQS) of 120 ppb. This ozone level places Chicago in the high sub-category of the "Severe" rating, the worst rating outside the Los Angeles air basin.[8] Of all CWE's fossil steam generation, only Kincaid and Powerton are outside the non-attainment area.[9] The State of Illinois is obligated under the Clean Air Act to reduce the emissions of ozone precursors (organic compounds and Nox) by at least 3% annually, and achieve compliance with the NAAQS by 2007.

Through 1996, utility boilers are only likely to be required to implement Phase 1 RACT (Reasonably Achievable Control Technology), which essentially requires only low-Nox burners.[10] Since no low-cost technology is available for controlling cyclone emissions, cyclone boilers are exempt from RACT. However, the high emissions of the cyclone boilers are likely to require extensive controls, or shutdown of the boilers in the post-1996 Phase 2.

Q: What Nox control costs has CWE included in its fossil optimization

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[8]Serious and Moderate non-attainment problems along portions of the eastern shore of Lake Michigan may also be caused in part by Nox emissions in the Chicago area.

[9]Nox emissions can contribute to ozone problems many miles downwind. Emissions controls at Powerton and Kincaid may turn out to be necessary to allow Chicago to reach attainment economically.

[10]IEPA has proposed RACT values of 0.45 lb/MMBTU for coal and 0.20 lb/MMBTU for oil and gas (Draft of August 26, 1993, regulation 217.523). Collins may be able to comply with the oil/gas RACT by operating on gas (with new burners), and seven coal units are reported to have pre-control emissions lower than the RACT level. Since RACT averaging is also proposed (regulation 217.525), CWE may be able to delay low-Nox burners at a few more units.

assessment?

A: CWE is unwilling to specify, by unit or by project, the Nox control measures included in the FOP cost estimate, the cost of these modifications, the basis for the cost estimates and the effect of each modification on the unit emissions (CWE responses to JDR-85, 86). CWE appears to have included some Nox control measures in its fossil optimization assessment (CWE response to JDR-85, 86), but will reveal only that it projects the total cost of all environmental modifications (including an SO_2 scrubber on Kincaid installed in 1999) to be $510 million.

In the Initial Clean Air Compliance Plan, CWE estimated the cost of the Kincaid scrubbers (with initial landfill development) to be $295 million if installed by 1995 and $370 million if installed by 2000. If the scrubber cost in 1999 is $350 million, the budget leaves only $160 million (presumably in mixed years' dollars) for all other environmental modifications reflected in the fossil optimization assessment.

Q: Why do you believe that CWE has not included sufficient Nox control cost estimates in its fossil optimization assessment?

A: Several considerations suggest that CWE has not included the full costs of bringing its fossil plants, especially the cyclone boilers, into compliance with Title I. First, the 1/17/94 affidavit of Mary F. O'Toole states that "Edison has no additional information" about the requirements of the Ozone Non-Attainment Program nor any plan for Title I compliance of its cyclone boilers. Nox controls on cyclone boilers were not included in the Company's environmental implementation strategy, and hence were not included in the costs of the FOP (CWE response to JDR-85).

Second, it is unlikely that $160 million will cover all compliance costs other than Kincaid scrubbers. A total cost of $160 million for life extension of CWE's 10,268 MW of fossil steam generation (CWE response to JDR-83g) amounts to only $16/Kw, which may be just enough to cover CWE's estimates of the cost of continuous emission monitors for all units and low-Nox burners for non-cyclone compliance with Title IV and the first phase of Title I.

Third, coal reburn, CWE's only identified potential Nox control measure for its cyclone boilers, is not commercially available (CWE response to JDR-86b). The costs of those controls would be subject to considerable uncertainty. In light of the limited cost information claimed in the discovery responses and in Ms. O'Toole's affidavit, it is unlikely that CWE has included any such uncertain costs in its fossil optimization assessment.

Q: Could Nox control costs have a substantial effect on the costs of life extension, especially for cyclone boilers?

A: Yes. CWE considers the coal reburn technology to be a potential control measure for its cyclone boilers (CWE response to JDR-88). NESCAUM (Northeast States for Coordinated Air Use Management, the coordinating group for New England, New York, and New Jersey air regulators) estimated that natural gas reburn will cost \$35 to \$50/Kw, depending upon the capacity of the boiler, and that the capital cost of coal reburn would be comparable.[11]

Coal reburn, which would reduce emissions by only 40%, may not be enough to bring cyclone boilers into compliance. Therefore, these units may require additional costly controls, such as selective catalytic reduction (SCR) or selective non-catalytic reduction (SNCR). The potential costs of these control measures vary with the age, size, and design of the plant; the costs for small, old, cyclone units may be higher than the range usually estimated. SNCR, which may achieve reductions in the range of 40-70%, has a capital cost estimated to be in the range of \$5 to \$16/Kw, and an operating cost of 0.5-4 mills/Kwh.[12]

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[11] *Evaluation and Costing of NO_x Controls for Existing Utility Boilers in the NESCAUM Region*, Control Technology Center for Northeast States for Coordinated Air Use Management (NESCAUM), December 1992, pp. 6-14 - 6-15.

[12] Ian M. Torrens and Jeremy B. Platt, "Electric Utility Response to the Clean Air Act Amendments," *Power Engineering*, January 1994, p. 46; and Bemis, *et al.*, "Technology Characterizations," Staff Issue Paper #7, Docket No. 88-ER-8,

SCR, which may reduce emissions by 70-90%, is estimated to cost $70/Kw to $150/Kw.[13] SCR will, in addition, have operating costs, including costs for ammonia or urea injection and for catalyst replacement.

Q: How would more realistic consideration of unit-specific life extension costs affect avoided costs?

A: More realistic consideration of life extension on a unit-specific basis would result in higher avoided costs. First, if life extension of certain units is not found to be economically feasible, retiring those units will raise energy costs in the short term and require spending on replacement baseload/cycling capacity in the long term.[14] Second, some required Nox controls, especially on the cyclone boilers, may significantly increase variable O&M, and hence, avoided energy costs. Third, DSM may defer some marginally cost-effective life extension expenditures. In that case, DSM would defer or avoid the highest cost refurbishments that pass in the base case, not the average.

More realistic treatment of life extensions would also reduce costs to ratepayers, since less expensive resources can be procured to avoid spending millions of dollars on potentially futile attempts to extend the lives of old, small, expensive, and inefficient coal plants.

2. **Fossil Unit Performance**

Q: What expectations does CWE have for the performance of the fossil steam units?

A: CWE forecasts that unit reliability and heat rates will generally improve

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California Energy Commission, September 6, 1989. Since the 4 mill estimate is for SNCR with urea injection on a gas plant, the cost for a coal plant may be even higher.

[13]Torrens and Platt (1994), p. 46.

[14]CWE agrees, as states d in the 1992 Main Report (p. III-33):
> ...The need for [new] coal units would, however, be advanced if life extension of some existing fossil steam capacity should later be found not to be economically justified.

and that there will be no increases in fixed or variable O&M, despite possible unit degradation or environmental modifications.[15]

Q: What is the basis for these optimistic forecasts of unit performance?

A: Despite requests for this information, CWE has not documented the basis for its forecasts of unit performance and O&M costs. CWE states only that (1) the estimates of unit performance characteristics were based on "previous performance and engineering judgment, not on the fossil optimization assessment" (CWE response to JDR-80) and (2) CWE cannot even estimate the effects of environmental retrofits on performance, until the specific vendor and the equipment are selected (CWE response to JDR-86e).

Q: Do you believe that this "engineering judgment" is a reliable basis for unit performance assumptions?

A: No. It is not clear how reliable an engineering judgment can be if it does not even consider the unit-specific projects developed in the fossil optimization assessment or the effects of environmental modifications.[16]

CWE may instead have based performance assumptions on some general engineering knowledge about the effects of life extension on plant performance. If so, such generalizations are of questionable validity. The fossil optimization assessment does not appear to include retrofits aimed at improving heat rate (CWE response to JDR-83d). There is no reason to expect that retrofits selected to improve plant availability and to meet environmental regulations will also improve operating efficiency and maintain O&M cost at the historic level. Indeed,

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[15]This discussion of CWE's forecast of unit performance and O&M costs is based on the inputs to the EGEAS model, which are documented in Appendix VI.S to CWE's 1993 Supplement. I have assumed that CWE made similar assumptions in the calculation of avoided energy costs. Unfortunately, CWE has not provided the inputs to the PROMOD production costing model.

[16]CWE's identification of unit-specific projects may have been too preliminary to be a reliable basis for forecasting unit performance, in any case.

adding environmental controls and redundant or more robust equipment to improve reliability may increase operating costs and increase heat rate by increasing internal energy use, reducing boiler efficiency, or decreasing heat transfer.

Q: Can environmental retrofits have a substantial effect on unit performance and increase O&M costs?

A: Yes. Environmental retrofits may adversely affect thermal efficiency, combustion efficiency, and plant reliability. In addition, some environmental controls have significant O&M costs, as noted above.

Q: How does the forecast of unit performance affect avoided costs and least cost planning?

A: In two ways. First, unit performance and O&M costs would affect the results of any reasonable cost-effectiveness analysis of unit life extension (though not necessarily the results of CWE's aggregate analysis). Second, the performance and variable O&M costs of life-extended units affect avoided system energy costs.

3. **Zion Station Retirement**

Q: How does CWE treat existing nuclear capacity in the avoided cost and integration analyses?

A: CWE assumes a 40-year life for all nuclear units. CWE takes the position that all anticipated repairs and refurbishments of its nuclear units are cost-effective and premature retirements are uneconomic.

Q: Is CWE's position based on any cost-effectiveness analysis?

A: Yes. Because of several near term major expenditures anticipated for Unit 1, including steam generator replacement, CWE performed an analysis of premature retirement of Zion (1992 LCP, p. III-47). CWE concluded from this analysis that early retirement of Zion was not economically justified and considers this result to be "a generic demonstration" applicable to all of its nuclear units. (CWE response 40

Alan: Not a typo?

Q: Please summarize CWE's analysis of Zion station.

A: Edison estimated the cost-effectiveness of continued operation of the Zion station by assuming that both units would be retired in the beginning of 1993. Although Edison provided the EGEAS model output from the retirement run, it did not provide inputs, workpapers, or other documentation of its assumptions.

Q: Have you identified flaws in CWE's approach?

A: Yes. Even without detailed documentation, it seems clear that the Company's assumptions biased results in favor of continued operation of at least Zion 1. In particular:

- The analysis assumed a retirement date, the beginning of 1993, that may be several years prior to the date of major capital expenditures.[17] This unduly burdens the retirement case with premature replacement costs.
- Edison looked at the cost-effectiveness of retiring the entire station, rather than at each unit individually. If total station capital additions are predominantly attributable to Zion 1, then the optimal plan might be to retire Unit 1 and continue operation of Unit 2. This is essentially the same problem identified in the Edison's fossil steam life extension analysis.
- Edison does not appear to have considered alternative scenarios for delaying the steam generator replacement (or retirement), with tube plugging and sleeving. These scenarios would include plugging and sleeving until steam generator replacement can no longer be safely deferred. After that time, the delayed retirement scenario would include the cost of replacement capacity, and the delayed replacement scenario would include the costs of a new steam generator.

4. **Recommendations for Life Extension Assumptions**

Q: How should CWE take into account its projected life extension investments in its least cost planning?

[17]CWE has failed to specify how long Zion Unit 1 could run without steam generator replacement.

A: In the absence of a valid analysis of the fossil optimization program and Nox control requirements for coal plants, CWE should prepare a plan that assumes retirement of all coal units, with no life extension investments.[18] The retirement dates can be taken from CWE's base case estimate of retirement dates without FOP, provided in CWE's response to CDR 7-155. In addition, unless CWE can demonstrate that steam generator replacement is cost-effective, the retirement plan should include retirement of the Zion units when the steam generators for each unit would otherwise need to be replaced.

B. **Other Environmental Compliance Costs**

1. **SO_2 Emission Costs**

Q: What are the potential costs to CWE of SO_2 emissions?

A: CWE will be required, under the CAAA, to hold emissions allowances for every ton of SO_2 it emits.

Q: Does CWE include SO_2 compliance costs in its avoided costs?

A: It is unclear. CWE says that it reflects SO_2 allowance costs in its avoided costs by adding an "Emission Penalty" to fuel costs in the production costing runs (CWE response to JDR-67). However, there is statement in the 1993 Summary Report that suggests that CWE may have eliminated SO_2 costs from its avoided costs, by assuming a zero Emission Penalty for some or all of its generating units:

> SO_2 emissions allowance costs are assumed to be $285 per ton in 1995$ and assumed to escalate at 4% annually. Based on the current Plan, CWE expects to have adequate allowances to supply customer electricity requirements without having to purchase additional SO_2 emissions allowances (p. VI.S-2).

[18]It may be relatively easy to separately screen the cost-effectiveness of life extensions for Joliet 7 & 8, Powerton and Kincaid, the largest and newest coal units.

Q: Would it be appropriate to assume a zero Emissions Penalty if CWE does not have to purchase additional allowances?

A: No. SO_2 allowances should figure into the calculation of DSM benefits even when the Company will not have to purchase additional allowances, because reductions in sulfur emissions due to DSM will free up allowances for sale in the allowance trading market.

CWE may have reflected SO_2 allowance costs correctly. Unfortunately, the Commission cannot tell from the documentation CWE has provided. CWE's response to JDR-67 asserts that CWE applied Emission Penalties to fuel costs in the PROMOD runs used to develop avoided energy cost. However, CWE specifies only the formula, not the actual Emission Penalty inputs. Given the significance of environmental compliance costs, CWE should have been clear in its discovery response.

2. **Other Nox Emission Cost**

Q: Are there potential costs to CWE of emissions of Nox aside from its effects on plant retirement and plant performance?

A: Yes. New units will have to obtain offsets of their potential Nox emissions. The costs of purchasing these offsets (or of not selling internally-generated offsets) should be included in the costs of all new units.

The Illinois EPA has announced that it is developing an allowance trading system for Nox. Allowance trading will probably allow Illinois to attain ozone compliance at the lowest possible cost, since it would avoid much of the inefficient command-and-control approach. CWE should determine whether a trading program is likely to apply to existing units; if so, Nox emissions, like SO_2, would appropriately be reflected in the production costing modeling as a fuel cost adder. If not, CWE should be assuming worst-case control requirement for Nox at its existing units.

3. **Air Toxics**

Q: Are there any potential costs to CWE from other portions of the CAAA?

A: Yes. Title III requires controls on air toxics from non-utility sources, and studies to determine the role of utility plants in mercury and other air toxics problems, particularly for the Great Lakes. Since coal plants are major emitters of heavy metals (especially mercury), and since CWE's plants are upwind of the Great Lakes, additional controls for fine particulates (such as baghouses) and for gaseous mercury (perhaps scrubbers) are likely for CWE's coal plants. These controls will generally reduce net power output, increase variable O&M, and impose capital costs, improving the economics of earlier retirement for these units.

4. Recommendations for Other Environmental Costs

Q: What are your recommendations for the treatment of other environmental costs in the Least-Cost Plan?

A: CWE should be required to include all the costs of environmental compliance in DSM avoided costs, screening of supply options, and integration of its Least-Cost Plan, and to demonstrate that these costs are included. At a minimum, CWE should be including the costs of sulfur allowances for all fossil units and of Nox offsets for new units. In addition, unless CWE has reason to believe that Nox trading will not occur, or that its units will not be affected by mercury or other heavy metal controls, mid-range estimates of these costs should be included in avoided costs, the determination of whether continued operation of older existing units is likely to be cost-effective, the screening of supply options, and the integration of supply and demand.

C. Avoided Distribution Costs

Q: Has Edison provided support for its assumption that avoided distribution costs are zero?

A: According to CWE, the studies that support its exclusion of distribution costs are either too burdensome to provide or not relevant (CWE responses to JDR-64 and 66).[19] The only support CWE offers is a one-page memo provided in the 1992 LCP filing. In that memo, CWE actually acknowledges that some programs can

[19]It is curious that CWE considers to be irrelevant studies that could confirm CWE's assumption that distribution cannot be avoided.

avoid distribution costs, but only in the case of customers served from an Electric Service Station (ESS). CWE contends further that transformers are "lumpy" and sized to allow for future load growth, and as a result, only programs that are full-scale and produce large (15%) reductions in the total load of a new customer and/or large reductions in new loads of existing customers can reduce distribution costs (1992 LCP, p. IV-C-249).

Q: What is an ESS and what customers are served from an ESS?

A: ESS's are transformer installations that are designed to serve only one customer (CWE's response to CDR-86). These customers can be high voltage or primary customers, and most primary customers are served from an ESS (CWE's response to CDR-84).

Therefore, CWE assumes that distribution costs can be avoided only in the case of high voltage or primary customers with dedicated transformer facilities.

Q: Does CWE's rationale for assuming that no distribution costs are avoidable have any merit?

A: No. It has several fatal flaws:

- ESS's are not the only distribution equipment affected by customer load.
- Decreases in existing loads, not just reductions in new customer load or load additions, can avoid future distribution investment.
- Reductions of *less* than 15% in the load of new customers or in load additions of existing customers can avoid distribution investment.
- Comprehensive DSM programs can produce the 15% load reductions that CWE believes is necessary to avoid distribution costs.

CWE's position poses a Catch-22. Many cost-effective conservation measures may fail screening because CWE has ignored a significant portion of their benefits. As a result, CWE is less likely to implement the comprehensive DSM programs that in CWE's judgment would reduce distribution costs.

Q: Is there any merit to CWE's contention that distribution costs can be avoided only in the case of customers served from an ESS?

A: No, for two basic reasons. First, transformer capacity in a distribution substation or a line transformer can be avoidable whether it serves a single customer or a group of customers. Second, the sizing and number of distribution equipment other than transformers also depend on load.

Q: Why does CWE assume that reductions in existing load cannot reduce transformer investment?

A: CWE explains that it is not "standard Company practice" to replace an existing transformer with a smaller unit when there is a reduction in the customer's load. (1992 LCP, p. IV-C-249).

Q: If this is correct, how can decreases in existing loads reduce distribution investment?

A: Decreases in existing loads can avoid future distribution costs in several ways, including:

- Reducing existing load frees up existing distribution capacity for other customers and other loads and delays the need for additional capacity to serve load growth.
- Distribution expenditures may be required to catch up with past load growth.
- Current and expected load determines the sizing of equipment replacing older equipment that wears out with age and use.
- Existing distribution equipment wears out faster if it is more heavily loaded.

Q: What is the basis for CWE's contention that only large reductions in load can avoid distribution investment?

A: CWE argues that the available distribution equipment and system design criteria are such that large changes in load are required to reduce the cost of new transformer installations. CWE offers two assertions to support this position: First, CWE correctly notes that transformers come in a limited number of sizes, and as a result (according to CWE), the sizing of transformer installations is "lumpy." CWE asserts that this lumpiness eliminates any response to small reductions in load. Second, CWE claims to size new transformers at 15% above initial load requirements, to provide for future load growth. CWE asserts that this reserve capacity reduces the opportunity for reductions in sizing of transformers.

As an illustration of its argument, CWE calculates the load reduction necessary to justify installation of a transformer of the next smallest size for a particular customer. "Making some assumptions about the type of customer and our equipment," CWE concludes that a load reduction of 29 kVA would be necessary to reduce a customer's transformer requirement from 112 KVA to 75 KVA, and a load reduction of 380 KVA to reduce the customer's transformer requirement from 1500 KVA to 1000 KVA (1992 LCP, p. IV-C-249).

Q: Do you find CWE's examples convincing?

A: No. CWE's calculations depend upon an unrealistic model of distribution design, and as a result overstate the load reductions necessary to affect transformer investment.

Q: What unrealistic assumptions does CWE rely upon?

A: First, CWE assumes that "there is exactly 15% of load remaining before the [larger pre-DSM] transformer would be considered overloaded" (1992 LCP, Appendix IV, P. IV-C-249), or that the new customer's pre-DSM load is at the maximum design loading of the larger transformer. While I have not been able to reproduce CWE's results precisely, Table ~~2~~ 1 shows a close approximation to CWE's estimate of the load reduction required to downsize 1500 KVA and 112 KVA transformers, *if* *they are loaded to 85% of nameplate capacity*. Each KVA of transformer capacity saved requires 0.85 KVA of load reduction, and the reductions must be a large fraction of pre-DSM load. less than .85

Since customer loads are spread continuously over a wide range, CWE's examples are hardly typical for actual practice. Some customers are fully using their dedicated distribution equipment (as in CWE's examples), some are overloading their equipment (in which case DSM will avoid upgrading, early replacement, or both), some are barely using the equipment enough to justify the existing sizing, and most lie between these extremes.[20]

Table ~~3~~ 2 illustrates a situation in which the pre-DSM load is 5% higher than the loads for which smaller transformers would be installed. Even a small reduction in load allows for a large reduction in transformer capacity.

Second, CWE's calculation unrealistically assumes that a single large customer is served by only a single transformer and that if load is not reduced to the design level of the next smaller size transformer, CWE will necessarily install the larger unit. In actuality, a single customer may be served by several transformers.[21] Utilities generally install a bank of transformers designed to minimize cost and permit reliability of service.[22] Using CWE's example, a customer with a pre-DSM 1500 kVA capacity requirement (a 1,275 kVA load and a 15% reserve margin for growth) may not be served by a single 1500 kVA transformer, but rather by a few transformers, such as by three 500 kVA transformers. In this situation, a DSM program would not have to reduce the customer's load by 380 kVA, as CWE claims, to avoid transformer costs. Instead,

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[20]The same is true for the effect of new customers and new loads, except that overloading is less likely in these circumstances.

[21]Utilities generally install a bank of transformers designed to minimize cost and permit reliability of service.

[22]Multiple transformers permit essential services when some transformers have to be taken out for repair. In addition, several smaller transformers may serve a single building or complex because the transformers were added over time as load grew.

as shown in Table ~~4~~ 3, a load reduction of only 170 kVA would enable CWE to install a 300 kVA transformer in place of one of the 500 kVA units. Table ~~4~~ 3 also shows that a load reduction of only 85 kVA (or 7%) would be sufficient to reduce transformer sizing for a customer with a pre-DSM load midway between the maximum loads for the 300 kVA and 500 kVA transformers.

Third, CWE ignores distribution networks, such as in downtown Chicago, on which systems of transformers serve many customers. On this system, small changes in the loads of individual customers can add up to a large enough load reduction to change the capacity required on one of the transformers. Similar systems are used for other customers: a group of suburban stores may be served by a common transformer bank, and a street of houses may all share a single transformer.

Q: Are there non-transformer distribution costs that are avoidable?

A: Yes. In addition to the transformers in substations and at the customers' premises, DSM avoids costs of distribution lines and auxiliary equipment. Load levels affect the sizing and number of distribution conductors in each primary feeder and lateral, secondary line, and service drop. The number of feeders and other lines is also determined by load; as load grows and existing lines are overloaded, utilities add new feeders, along new routes. As a result, the number and size of poles, conduit, trenching, and other non-load-carrying distribution investments varies with load growth. Lastly, investments in such auxiliary equipment as capacitors, regulators, and switches are largely driven directly by load or by the number and length of lines, which are driven by load.

Q: Do other utilities credit DSM with avoided distribution costs?

A: Yes. Without doing extensive research on the question, I am aware of a number of utilities that include avoided distribution costs in valuing DSM, namely: Baltimore Gas & Electric, Boston Edison, Central Maine Power, Central Vermont Public Service, Consolidated Edison, Long Island Lighting, New York State Electric and Gas, Niagara Mohawk Power, Massachusetts Electric, and Potomac

Electric Power.

Q: What data or analyses specific to CWE indicate that avoided distribution costs on the CWE system are substantial?

A: While CWE regards the actual distribution system design as critical to the examination of avoided distribution costs, CWE has not provided the distribution design guidelines and distribution construction plans that would permit calculation of CWE's avoided distribution costs.[23]

However, CWE has made available its estimates of marginal distribution costs. In his 1990 Cost-of-Service Study testimony, Paul R. Crumrine estimated marginal distribution cost for residential customers to be about $100/peak kW-year (in 1991$). This figure is comparable in magnitude to CWE's avoided generation and transmission capacity costs in 1996 and with a 60% load factor, it amounts to about $.02/kWh.

Q: Have you evaluated CWE's marginal distribution cost estimates?

A: CWE's marginal cost analysis is a very detailed examination of the engineering requirements of CWE customers. My review of this analysis indicates that it includes all levels of the distribution system, from substations to secondary (but not services), and that it is generally internally consistent. However, I have identified an error in the conversion of the engineering estimates from $/kVA of equipment capacity to $/kW of load.[24] Correcting this

[23]CWE will make distribution guidelines available for review, but objects to the copying of any information in its guidelines (CWE response to JDR-65). This does not permit the extensive review necessary for an analysis of CWE's avoided distribution costs. I have never encountered any other utility that considered its distribution guidelines to be confidential.

[24]CWE's marginal-cost workpapers indicate that the costs of line transformers and secondary lines are computed in $/kVA of transformer capacity, but that those costs are used as $/kW of class non-coincident peak (the class peak on the day of system peak; the sum of class peaks is very close to system peak). The kVA of transformer capacity for the CWE system as a whole is roughly twice the peak kW load, for two reasons. First, transformer loads are much more diverse than class peaks; the sum of transformer loads is almost inevitably

conversion error would slightly increase CWE's estimate of marginal distribution costs.

Q: With that correction, would CWE's marginal distribution cost estimates be a reasonable proxy for avoided cost estimates?

A: Yes. CWE's marginal cost estimates are based on a Company-specific engineering study of specific equipment needs of various classes and types of customers as a function of their loads. It is reasonable to expect that the distribution costs that CWE has determined to be marginal (i.e., will increase with load level) will also be avoidable by reductions in load or load growth.

1. **Recommendation**

Q: What are your recommendations regarding CWE's treatment of distribution costs?

A: The Commission should order CWE to include marginal distribution costs in its avoided costs and credit DSM with avoided costs in the integration process.

D. **Value of Off-System Sales**

Q: Has CWE realistically included off-system sales in computing the benefits of DSM?

A: No. CWE assumes that conserved energy can result only in reductions in plant output on a stand-alone basis, without off-system sales.[25] All low-cost generation is assumed to be available for retail load; none is assumed to be occupied with off-system sales (CWE response to CDR-36e(3) and (4)). In actuality, energy conserved by DSM will often reduce the usage of the marginal unit that would otherwise run to serve off-system sales, saving the higher

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higher than the class peak. Second, kVA measures apparent power, which is higher than the real power measured by kW; kVA at the transformer is generally higher than kW at the transformer. Transformers and secondary make up about 10%-25% of residential distribution costs; correcting CWE's error would increase marginal costs by a comparable percentage.

[25] CWE does include economy purchases in its EGEAS (CWE response to JDR-60), and apparently treats currently committed sales as part of its firm load (CWE response to JDR-57).

running costs of that unit, or free up either energy or capacity for off-system sales. If CWE can make additional off-system sales at a profit, it will decrease retail revenue requirements. The benefits of DSM should reflect additional profits (that is, the difference between sale price and avoided cost) due to DSM, as well as the higher avoided energy cost due to off-system sales.

Crediting DSM with its effect on off-system sales is consistent with the Least-Cost Energy Planning Rules, Section 440.310(a)(3). Recognizing the effect of off-system sales on avoided running costs is simply an issue of realistic forecasting.

Q: Is there likely to be a profitable market for CWE power?

A: Yes. First, CWE regularly sells economy power, especially in the off-peak period, in order to reduce system costs (1992 Main Report, p. III-52). CWE is one of the country's largest sellers of energy to other utilities. If CWE's avoided energy costs are low, conservation even in the off-peak periods, is likely to result in profitable economy sales.

Second, energy-saving DSM can provide opportunities for CWE to sell power through long-term agreements, such as the WP&L contract. According to the 1992 Main Report (p. III-51), CWE's sale to WP&L is beneficial to the ratepayer, because:

> Edison is able to sell higher valued intermediate type resources, while only needing to add less expensive peaking type resources to its system.

CWE states that it will continue to sell power to other utilities when it is profitable to do so. Unfortunately, CWE has refused to provide the information necessary to gauge the market for off-system sales. CWE has not specified the terms of the WP&L contract, nor provided data on recent solicitations or offers. Nevertheless, it is reasonable to expect, particularly if CWE's avoided energy costs are low, that off-system sales will increase over time, as other utilities grow into need for power and the market tightens.[26]

Q: Has CWE reflected off-system sales opportunities in avoided costs or integration analysis?

A: No. In the case of economy sales, it appears that CWE introduces a particular bias in its integration analysis by including economy purchases, but not sales. (CWE responses to CDR-36e, JDR-60). The only off-system sales reflected in CWE's avoided cost and integration modeling are committed contracts (CWE response to JDR-57).

Q: Does CWE consider off-system sales opportunities in supply-planning decisions?

A: Yes. As stated in the Supplemental Testimony of Jerome P. Hill (p. 5), one of the factors CWE considers in its resource planning is the "ability to be marketed off-system by Edison, if not needed by Edison's customer." In addition, CWE's 1990 Plan identified lost off-system sales as one of the costs of mothballing its fossil steam units.

CWE should consider off-system sales opportunities in its supply-side decisions, but it should apply comparable terms and methods in its consideration of supply and demand resources. Any resource that frees up energy or capacity for profitable sales is beneficial to the Company and its customers, whether that resource is conservation, a purchase from a non-utility generator, or some other resource.

Q: How should CWE take into account off-system sales opportunities in its least-cost planning?

A: CWE should either include a realistic forecast of off-system sales in the

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[26]CWE apparently projects very low avoided energy costs, which will tend to maintain its off-system sales. In addition, Wisconsin utilities are planning on adding coal capacity around the end of this decade; CWE existing coal plants should be able to profitably compete with the cost of new coal capacity.

consistent with fossil

production costing modeling (on which the avoided energy costs and integration analyses are based), or it should include the off-system sales margin in avoided cost .

1. **Recommendations**

Q: What are your recommendations regarding CWE's treatment of off-system sales?

A: CWE's decision to ignore all future firm and economy off-system sales, while including off-system purchases, understates avoided energy costs and biases the selection of new resources against energy-serving options, both for supply and demand resources. The Commission should order Edison to reflect a best estimate of future off-system sales in its production costing, through adding forecasts of off-system sales to system load, including an economy sales option in the production costing runs, and/or making adjustments to avoided costs after the production costing runs. This estimate should result in avoided costs that reflect the full value to CWE's firm customers of reduced usage of its baseload and intermediate power plants.

E. **Cost of Coal**

Q: How have CWE's projections of coal prices changed since the 1992 IRP?

A: According to CWE, the incremental cost of coal at the mine as well as the cost of rail transportation has declined as a result of recent coal supply and transportation contract renegotiations (1993 Supplement, Summary Report, p. III.S-3).

Q: What has been the effect of the contract revisions on the coal price forecast assumed in CWE's avoided costs and integration analysis?

A: That is not clear in the record. CWE has not provided the coal price forecast used in the avoided cost and integration analyses, and has not explained how it computed the forecast prices (CWE responses to JDR-69 and 70). Furthermore, CWE is unwilling to specify the pricing provisions of the coal supply and transportation contracts that apparently resulted in a reduction in the projected incremental cost of coal, and document how these provisions were taken into account in the coal price forecast. Indeed, CWE claims that it has not actually considered the contract details in its forecast of coal price (CWE responses to JDR-70 and 72).

Q: In what ways are the specific coal supply and transportation contract provisions relevant to the forecast of coal price used in avoided cost and integration analyses?

A: The structure of the contracts affect the avoided cost of coal in at least two ways. First, both the supply and transportation contracts require a certain annual minimum purchase: above that amount CWE may procure and transport coal on the spot market at lower-than-contract prices (if spot prices are below contract prices), but below that amount CWE must buy and deliver coal at the contract price. For purposes of computing avoided costs, the avoided coal supply is likely to be some mix of contract coal and spot coal, with the mix depending on CWE's contracts and annual coal consumption. The contract renegotiation apparently has reduced the annual minimum purchase and transportation volumes, and hence may have affected the mix of contract coal and spot coal on the margin. The effect of the contract renegotiation on this mix depends upon revisions in the annual minimum requirements and the forecasted total coal consumption.

Take-or-pay provisions of the contract may also affect avoided coal cost, when contract coal is in the avoided mix. The take-or-pay component of price is essentially sunk. Only the residual is affected by coal consumption. For example, for certain prior coal supplies, CWE was obligated to pay 75% of the contract price up front for mineral rights, and only 25% when the coal was mined and delivered. (Testimony of Robert Beckwith, CWE, Dockets 86-0511 and 87-0123)

Q: Do you have more specific concerns about the coal price forecast?

A: Yes. It is not at all clear that renegotiation of contracts should have led to reduction in coal price input to avoided cost computation, as CWE appears to claim in the 1993 Supplement (Summary Report, p. III.S-3). In particular, it appears from CWE's response to JDR-73 that the 1992 Plan computed avoided costs using only the "incremental" 25% of total coal supply costs under the older contracts; it is difficult to believe that the contract renegotiation has reduced incremental coal price below 25% of the prior contract coal price.[27]

CWE's description of the contract revisions is unfortunately vague, but it appears that the major benefit of the supply contract renegotiation is a lower volume commitment, not a lower contract price. The lower commitment will free CWE of some take-or-pay costs, and permit it to buy more of its coal on the spot market. A lower volume commitment may reduce CWE's total coal costs, but not necessarily its avoided coal cost.

If CWE *has* reduced its forecast of incremental coal price, CWE's claim that it has not considered the contract details and projected coal volumes in developing the forecast of incremental coal price sheds some doubt on the reliability of the coal price forecast.

Q: Where has CWE's failure to document the coal price forecast left the least-cost planning review?

A: Given the lack of documentation of the coal price forecast, which is a major portion of Edison's avoidable energy costs, the avoided cost, screening and integration analyses are simply unreviewable.

1. Recommendations

Q: What are your recommendations regarding CWE's coal price forecast?

A: CWE should be ordered to provide the coal price forecast used in the Plan, the basis for that forecast and a demonstration that the forecast is reasonable and consistent with the provisions of the supply and transportation contracts. No unreasonable confidentiality requirements should be imposed for access to this

[27]Due to CWE's refusal to document its avoided costs, the record is unclear as to whether the term "incremental" refers to the same contracts or the same costs in each place that CWE uses the term.

data.

IV. Screening Issues

A. Timing

Q: Is CWE's timing of DSM investments consistent with CWE's treatment of supply resources?

A: No. CWE's Plan includes expenditures on both new and existing supply resources before the 1996 need date identified in the 1993 Supplement.[28] The Plan includes sizable investments for life extension of existing fossil steam units as well as additions to peaking capacity in 1994 and 1995, even though CWE was not expected to "need" capacity until 1996.[29] In the EGEAS integration runs,[30] the peaker refurbishments in 1994 and 1995 are considered a new supply option.

B. Load-Shape

Q: How does CWE screen DSM options for load shape effects?

A: CWE selects arbitrary weights for each of at least 10 load-shape objectives,[31] and then multiplies those weights by rough measures of each option's effect on load shape. Based on the resulting "DSM rank," CWE eliminates options without even screening them for cost-effectiveness:

> "DSM technologies that are clearly unsuitable for meeting Edison's load shape objectives are eliminated ... from further

[28]The need date may now be later than 1996.

[29]The life extension expenditures are planned not only in advance of the need for new peaking capacity, but also long before energy-serving capacity is needed.

[30]Refurbished peakers appear as an option in the RFP competitive bidding case (1993 Supplement, Appendix VI.S, pp. VI.S-A-67 and 68).

[31]Summer load shifting, peak clipping, "strategic" conservation and flexible load shape receive a weight of 10; summer valley filling, a weight of 7; winter load shifting, a weight of 8; winter valley filling, a weight of 7; winter strategic load growth, a weight of 5; winter flexible load shape, a weight of 2; and all other load shape objectives (presumably including winter conservation) a weight of 0 (1992 Main Report, p. IV-76).

consideration." (Main Report, p. IV-73).

In essence, DSMRank is a simple accounting program that ratifies CWE's preconceived notions about DSM. CWE picks the weights, rates the "applicability" of each DSM option, and selects the DSMRank cut-off point that determines which options are screened for cost-effectiveness. As a result, projects are eliminated based on CWE's prejudices, rather than on any substantive analysis.

Q: What is wrong with CWE's application of load-shape objectives in screening?

A: The approach assumes that the desirability of a load-shape change can be determined without any knowledge of the cost of the change, and only the roughest approximation of the benefit.

Depending on the cost and benefit of each option, any of the load-shape changes listed on page IV-76 of the 1992 Main Report may be desirable or undesirable from a societal perspective. For example, if a valley-filling measure is inexpensive to implement, displaces costly alternatives (e.g., fossil fuels in some industrial processes), and can be terminated before new baseload capacity is required or existing baseload capacity becomes valuable for resale, it may be very beneficial. On the other hand, if the measure is expensive, has little social benefit, and will increase system costs in the long term, it may be very undesirable. A broad category such as "valley-filling" is not particularly useful in screening programs or measures.

Q: Are there any of CWE's load-shape objective weights which you consider to be particularly inappropriate?

A: Yes. CWE gives no value to winter conservation. This understates the value of programs oriented toward reducing space-heating use and other winter-dominant uses (e.g., streetlighting). Such conservation reduces fuel costs, increases potential for off-system sales (especially of baseload capacity), and defers the need for new costly, intermediate and baseload plants.

Q: Should load-shape objectives have any role in least-cost planning?

A: To the extent that program designers know that certain kinds of load changes are particularly valuable, they can concentrate on identifying measures which achieve those types of changes. The Commission may also wish to impose stricter standards for the justification of promotional programs (e.g., valley filling and strategic load growth) than for conservation. However, for screening measures and programs, only the costs and benefits of each option are relevant.[32]

Q: What is the basis for CWE's load shape objectives?

A: CWE takes the position that its obligation under the least-cost planning regulations is limited to minimizing the cost of new resources, rather than minimizing total costs. According to CWE, therefore, the type of new supply needed determines the type of DSM that CWE will consider in its screening process. Until 2005, the only new capacity that DSM is deferring is peaking capacity (1992 Main Report, pp. IV-28). Hence, CWE will implement only DSM programs that reduce summer peak.

Q: Is CWE's reluctance to invest in energy-saving DSM consistent with its supply planning?

A: No. CWE's plan includes substantial near-term energy-saving expenditures on its fossil steam units, even though baseload capacity is not needed in the short term. In addition, the RFP bid resources that are planned for the period 1996 to 2000 are likely to include intermediate or baseload capacity. CWE's NUG screening does not reject a combined-cycle bid, for example, simply because the Plan does not indicate a need for intermediate capacity until 2005 (1992 LCP, Main Report, p. VI-28). To the contrary, CWE gives credit to NUG resources

[32]The benefits per annual kWh saved from a conservation measure will depend on the shape of the load effects, as well as the number of years a measure will persist.

installed before 2000 for deferring combined-cycle capacity in 2005 and after (1993 Supplement, Summary Report, p. III.S-7).

Q: Can energy-saving DSM investments avoid the costs of energy-serving supply resources?

A: Yes. First, conservation measures installed in the next few years will defer combined cycle capacity in 2005, just as intermediate or baseload NUGs would. Second, conservation can avoid near term expenditures on fossil optimization. Third, conservation can reduce system costs by improving opportunities for off-system sales.

Q: What meaningful distinction between new and existing resources can be made in least-cost planning?

A: The line between new and existing can be drawn in many places, for both supply and demand resources. For example, a life extension expenditure can be classified as a new resource, replacing the old plant at the time of scheduled retirement, or as an improvement on an existing supply resource. Similarly, replacing an aging, low-efficiency heat pump with a new CFC-free high-efficiency heat pump can be categorized as a new efficient resource or as an improvement on an existing HVAC system.

If CWE really believed it should make resource investments only when new resources are needed and should only make energy-saving investments when new baseload resources are needed, it would not be investing in the rehabilitation of existing baseload units.

Q: Should the least cost plan reflect existing resources?

A: Yes, it must. The choice of new resources depends on the capacity, operating efficiency (heat rate), fuel costs, and reliability of existing resources that survive into future years. Reasonable forecasts are important in resource selection. Least-cost planning is defeated if CWE forecasts lead to the rejection of 4¢/kWh new resources, forcing Edison to spend 6¢/kWh to retain and operate existing capacity.

Q: Can existing resources be reflected reasonably in the least-cost plan without being treated as options?

A: Yes. Existing-resource decisions can be reflected as part of the projections that are inputs to the new-resource least cost plan, so long as comparable methods are used for both demand and supply resources. For example, if CWE includes such energy-serving investments as life extensions of baseload plants and renegotiation of existing coal contracts as part of the supply-resource forecast, rather than as options in the least cost plan, it should also include cost-effective energy-saving conservation in the resource or load forecast, prior screening and selection of new resources.

1. **Recommendations**

Q: What are your recommendations regarding CWE's screening of DSM options by load shape and timing?

A: It is clear that CWE has a "current and continuous least-cost obligation" to its customers, even if the Least-Cost Plan itself need not consider modifications to existing resources as plan options. However, Edison does not appear to be precluded from including existing resources within the Plan, and actually has included some existing resource options. Planning will be more effective if all options in the Plan are considered using comparable methods, and I recommend that CWE consider alternatives for existing units as Plan options.

The Commission should require that CWE's plan reflect reasonable projections of existing resources, including the fuel costs, efficiency, reliability, and continued operation of existing units; off-system sales; deferral of life extensions; and temporary deactivation of existing units. All these projections are essential inputs to the timing and choice of new resources, which are the primary focus of the Plan. Any decisions that are not included as plan options should be included as forecasts, along with sufficient documentation to demonstrate that the projections are reasonable.

C. Tax Effects In Screening

Q: What tax effects does CWE reflect in its cost-effectiveness tests?

A: In its screening of C/I programs, CWE reduces participant savings to adjust for income tax increases due to rebates and decreased utility bills.[33] CWE reflects these tax effects as a cost in both the Participant test and the Total Resource Cost test.

Q: Why is CWE's inclusion of tax effects inappropriate?

A: CWE's inclusion of tax effects in the TRC test violates recommendation six of the statewide electric utility plan. In addition, CWE overstates the negative effect of taxes on the TRC benefit-cost ratio. As a result of CWE's miscalculation of tax effects, some cost-effective programs may appear to be uneconomic.

Q: In what ways does CWE overstate the tax effects?

A: CWE overstates the income tax increase for participants by including taxes on rebates and bill savings but ignoring the tax decrease resulting from participant program costs (capital investment and O&M costs). Since the rebate offsets participant expenditures, the immediate tax effect is determined by the difference between the rebate and the cost of the measure.[34]

In addition, CWE ignores the counterbalancing tax effects: if ratepayers pay

[33]CWE does not actually explain its calculation, but the ratio of Customer Income Tax Increase to the sum of Customer Bill Decrease and Customer Rebates Received is equal to 38.48%, the effective income tax rate CWE assumes (CWE's response to JDR-53). Hereafter, CWE's responses to Joint Data Requests will be identified as "JDR-#" and CWE's responses to the City's data requests will be identified as "CDR-#". misplaced footnote

[34]Rebates reduce costs and hence increase profits and income taxes for free riders; evaluation of effects on free riders should not include any measure costs, avoided cost, or lost revenues, since the measure would have been installed anyway. CWE does not appear to model the effects of DSM programs on free riders.

for lost revenues (net of avoided costs) and DSM program costs (rebates and administrative costs), their income tax bills will go down. CWE's treatment of tax effects in the TRC test is therefore inconsistent. If tax effects on participants are taken into account in the TRC test as a cost, the tax decreases to ratepayers should also be taken into account in the TRC test as a benefit.

Q: Can you give an example of CWE's miscalculation of tax effects?

A: Yes. As the DSManager output for the HVAC Retirement (Small Building) program demonstrates (Appendix IV, p. IV.S.-A-125), CWE's approach can have a nonsensical result. As shown in Table ~~1~~ 5, the program passes the TRC test, with net benefits of $515.5 million and a benefit-cost ratio of 1.85, before any customer tax effects. Obviously, only a portion of the net benefits are taxed, so the program must also be cost-effective after taxes. With CWE's selective recognition of tax effects, this program fails the TRC test, with a net cost of $68 million and a B-C ratio of .94. Table ~~1~~ 5 also shows that properly including a 38.48% income-tax rate on all costs and benefits reduces net benefits by only 38.48%, to $317.1 million, with a B-C ratio of 1.29.

Any C/I program that passes the TRC test, or equivalently, has positive net benefits, will produce a net tax increase, because the savings to the participants exceed the costs to ratepayers. However, taxes should not cause a cost-effective program to be uneconomic. Taxes are only a fraction of net benefits. Therefore, taxes will reduce the benefit-cost ratio of a cost-effective program, but not below a value of 1.

1. **Recommendations**

Q: What are your recommendations regarding CWE's treatment of customer income tax effects in screening of DSM options?

A: CWE should treat customer income taxes consistently and symmetrically. Since all benefits and costs to taxable commercial and industrial customers will be taxable, screening without customer income taxes almost certainly will not change the mix of DSM options that are cost-effective. Hence, I recommend that

Table 1

Estimate of Load Reduction Necessary to Downsize Transformers Based on Fully Loaded Transformers (CWE's Assumption)

	Transformer Size (kVA) [1]	Maximum Load (kVA) [2]	Difference Between Maximum Loads (kVA) [3]	Ratio of Load Reductionto Transformer Rating Reduction [4]	Required Load Reduction as Percent of Load [5]
<u>Large Transformer Case</u>					
Pre-DSM	1500	1,275			
Post-DSM	1000	850	425	85%	33%
<u>Small Transformer Case</u>					
Pre-DSM	112	95			
Post-DSM	75	64	31	85%	33%

<u>Notes:</u>

[1]: DSM could reduce transformer size from the larger to the smaller in each pair.

[2]: [1]× 85%

[3]: ([2] for larger) - ([2] for smaller); Note that CWE's results are slightly different.

[4]: [3] +(([1] for larger) - ([1] for smaller)

[5]: [3]+[2]

Table 2
Example of Downsizing Potential for Transformers With Loads Below Maximum

	Transformer Size (kVA) [1]	Example Load (kVA) [2]	Maximum Load for Next Smaller Transformer (kVA) [3]	Change in Load Needed for Downsizing (kVA) [4]	Change in Transformer Size Due to Downsizing (kVA) [5]	Ratio of Transformer Rating Reduction to Load Reduction [6]	Required Load Reduction as Percent of Load [7]
Large Transformer Case							
Pre-DSM	1500	893					
Post-DSM	1000		850	43	500	11.8	5%
Small Transformer Case							
Pre-DSM	112	67					
Post-DSM	75		64	3	37	12.6	4%

Notes:

[1]: DSM could reduce transformer size from the larger to the smaller in each pair.
[2]: ([1] for smaller)×85%×105%
[3]: ([1] for smaller)×85%
[4]: ([2] for larger) - ([3] for smalller)
[5]: ([1] for larger) - ([1] for smalller)
[6]: [5]÷[4]

Table 3
Illustration of Downsizing Potential for Transformers That Serve a Single Customer in Parallel

	Load (kVA)	Transformer Capacity Required (kVA)	Transformers Actually Used	Load Reduction (kVA)	Required Load Reduction as Percent of Load
	[1]	[2]	[3]	[4]	[5]
High Pre-DSM Load Case					
Pre-DSM	1,275	1,500	3 x 500 kVA		
Post-DSM	1,105	1,300	2 x 500 kVA + 1 x 300 kVA	170	13%
Low Pre-DSM Load Case					
Pre-DSM	1,190	1,~~4~~500	3 x 500 kVA		
Post-DSM	1,105	1,300	2 x 500 kVA + 1 x 300 kVA	85	7%

Notes:

[1]: Given. In the second example, the larger load is the average of 1,275 kVA and 1,105 kVA.

[2]: [1]÷85%, rounded to transformer sizes.

[3]: Number and size of the the transformers needed to meet the nameplate capacity in [2].

[4]: ([1] for larger) - ([1] for smaller)

[5]: [4]÷([1] for larger)

Table 4: Air Quality Status of CWE Fossil Steam Units

Unit [0]	On-Line Date [1]	40 Year Retirement Date [2]	Capacity (MW) [4]	Full Load Heat Rate [5]	Cyclone Boiler? [6]	In Chicago Non-Attainment Area? [7]	NOx Emissions (lbs/MMBtu) [8]
Collins 1	1978	2018	549	9886		yes	0.242
Collins 2	1977	2017	549	9840		yes	0.242
Collins 3	1977	2017	531	9793		yes	0.242
Collins 4	1978	2018	531	9793		yes	0.242
Collins 5	1979	2019	531	9793		yes	0.242
Crawford 7	1958	1998	220	10221		yes	0.330
Crawford 8	1961	2001	327	9900		yes	0.502
Fisk 19	1959	1999	316	10547		yes	0.491
Joliet 6	1959	1999	301	10093	yes	yes	0.949
Joliet 7	1965	2005	507	10162		yes	0.469
Joliet 8	1966	2006	525	10154		yes	0.318
Kincaid 1	1967	2007	544	11036	yes		1.148
Kincaid 2	1968	2008	544	11036	yes		1.368
Powerton 5	1972	2012	703	10419	yes		0.959
Powerton 6	1975	2015	703	10419	yes		1.110
State line 3	1955	1995	190	10511		yes	0.167
State line 4	1962	2002	306	9444	yes	yes	1.011
Waukegan 6	1952	1993	107	11554	yes	yes	0.861
Waukegan 7	1958	1998	333	9758		yes	0.334
Waukegan 8	1962	2002	299	10126		yes	0.278
Will Co. 1	1955	1995	156	10453	yes	yes	1.050
Will Co. 2	1955	1995	156	10453	yes	yes	0.964
Will Co. 3	1957	1997	263	9647		yes	0.395
Will Co. 4	1963	2003	522	9767		yes	0.395
			Total MW:	9713			

Sources:

[0]: List of plants from Attachment 4 to CWE response to CDR-7-1-55.

[2] - [6]: Commonwealth Edison Co. Least Cost Plan, Appendix VI: Integration; July 1992; pp.VI-B-21-27.

[7]: Non-Attainment areas from State of Illinois Rules and Regulations, Title 35, Subpart B, Section 211.3590. Power plant locations from Energy Information Administration (1989), Inventory of Power Plants in the United States.

Table 5: Effect of Income Taxes on DSM Screening - Small Building HVAC Retirement

	CWE Version	Without Tax Effects	With All Tax Effects	
Participant Income Tax Increase	$583,520.48		$499,798.93	[1]
Customer Capital Investment	$217,571.60	$217,571.60	$217,571.60	
Utility Administrative Cost	$390,380.72	$390,380.72	$390,380.72	
Total Costs	$1,191,472.80	$607,952.32	$1,107,751.25	
Customer Income Tax Decrease			$301,433.23	[2]
Electric Production Cost Decrease	$512,170.42	$512,170.42	$512,170.42	
Utility Generation Capacity Credit	$508,228.23	$508,228.23	$508,228.23	
Utility Transmission Capacity Credit	$103,057.05	$103,057.05	$103,057.05	
Total Benefits	$1,123,455.70	$1,123,455.70	$1,424,888.93	
Net Benefits	**($68,017.10)**	**$515,503.38**	**$317,137.68**	
Benefit:Cost Ratio	**0.94**	**1.85**	**1.29**	

Sources:
All data from 1993 CWE LCP
[1] CWE version - 38.48%*customer capital
[2] 38.48% * {rebates+lost revenues+administrative cost-avoided costs}
Present value at 9.5% of rebates and lost revenues from ratio of PVs of participant income taxes at 13% and 9.5%, times PV of rebates and lost revenues at 13%.

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Corrected

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		Total MW:	9713				

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