8 613
p 20

COMMONWEALTH OF MASSACHUSETTS
ENERGY FACILITIES SITING COUNCIL

Massachusetts Municipal Wholesale Electric Company
E.F.S.C. No. 79-1

TESTIMONY OF PAUL L. CHERNICK ON BEHALF OF THE ATTORNEY GENERAL

FRANCIS X. BELLOTTI
ATTORNEY GENERAL

By: Alan D. Mandl
Assistant Attorney General
Utilities Division
Public Protection Bureau
One Ashburton Place
Boston, MA 02108
(617) 727-1085

November 5, 1980

Q: Mr. Chernick, would you please state your name, position, and office address.

A: My name is Paul Chernick. I am employed by the Attorney General as a Utility Rate Analyst. My office is at One Ashburton Place, 19th Floor, Boston, Massachusetts 02108.

Q: Please describe briefly 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 same school in February, 1978 in Technology and Policy. I have been elected to membership in the civil engineering honorary society Chi Epsilon, to membership in the engineering honorary society Tau Beta Pi, and to associate membership in the research honorary society Sigma Xi. I am the author of <u>Optimal Pricing for Peak Loads and Joint Production: Theory and Applications to Diverse Conditions</u>, Report 77-1, Technology and Policy Program, Massachusetts Institute of Technology. During my graduate education, I was the teaching assistant for courses in systems analysis. I have served as a consultant to the National Consumer Law Center for two projects: teaching part of a short course in rate design and time-of-use rates, and assisting in preparation for an electric time-of-use rate design case.

Q: Have you testified previously as an expert witness?

A: Yes. I have testified jointly with Susan Geller before the Massachusetts Energy Facilities Siting Council and the Massachusetts Department of Public Utilities in the joint proceeding concerning Boston Edison's forecast, docketed by the E.F.S.C. as 78-12 and by the D.P.U. as 19494, Phase I. I have also testified jointly with Susan Geller in Phase II of D.P.U. 19494, concerning the forecasts of nine New England Utilities and NEPOOL, and jointly with Susan Finger in Phase II of D.P.U. 19494, concerning Boston Edison's relationship to NEPOOL. I also testified before the E.F.S.C. in proceeding 78-17 and 78-33, on the 1978 forecasts of Northeast Utilities and Eastern Utilities Associates, respectively; jointly with Susan Geller before the Atomic Safety and Licensing Board in Boston Edison Co., et. al, Pilgrim Nuclear Generating Station, Unit No. 2, Docket No. 50-471 concerning the "need for power"; in D.P.U. 20055 regarding the 1979 forecasts of EUA and Fitchburg Gas and Electric, the cost of power from the Seabrook nuclear plant, and alternatives to Seabrook purchases; in D.P.U. 20248 on the cost of Seabrook power; in D.P.U. 200 on Massachusetts Electric Company's rate design and conservation initiatives; in D.P.U. 243 on Eastern Edison's rate design; and in PUCT 3298, on Gulf States Utilities' Texas retail rate design. I have also submitted prefiled joint testimony with Ms. Geller in the

Boston Edison time-of-use rate design case, D.P.U. 19845, but we have not yet testified.

Q: What is the purpose of this testimony?

A: In my testimony, I will respond to MMWEC's testimony on "alternatives", the one major topic which was excluded from consideration in D.P.U. 20248, but which is included in this proceeding. I will demonstrate that several alternatives, including conservation, deserve a place in MMWEC's supply planning, based on their competitiveness, or even superiority, compared to an expanded nuclear construction program.

Q: Does the analysis presented by Ian Forbes in this proceeding represent an appropriate comparison of the cost of power from Seabrook with that from alternative sources?

A: No. Dr. Forbes' analysis is flawed in three major respects:

1. the methodology is inconsistent and incorrect;
2. the nuclear costs utilized are far too low; and
3. a large number of promising power supply alternatives are ignored.

Q: In what respects is his methodology inconsistent and incorrect?

A: His methodological errors include:

1. using constant-dollar (real) prices with current-dollar (nominal) carrying charges;
2. mixing fixed and escalating costs;
3. neglecting selected real cost and benefit components (AFUDC, "contingency", timing);

4. using MMWEC's private, heavily subsidized cost of capital, instead of social cost;

5. treating a kwh from peaking capacity as less valuable than one from baseload capacity;

6. and treating the concepts of "fuel saver" and "backup capacity" inconsistently.

The ERG methodology appears to combine

capital costs, in (a form of) constant 1979 dollars;

carrying charges, in nominal terms, that is based on MMWEC's estimated cost of capital; and

O & M, fuel, and similar charges levelized in real, rather than nominal, terms.

Hence, the resultant costs represent neither economic cost (present value) nor normal accounting costs. Stating carrying charges in real terms would produce a present value cost; stating all costs in current dollars would produce a cost measure closer to standard accounting costs. The ERG methodology produces a variant of first-year accounting costs, with capital costs levelized in current dollar (nominal) terms, with operating costs escalating at the rate of inflation (that is, levelized in real terms), and with all first-year costs deflated to 1979 dollars. While the resulting costs can be compared for various technologies, it is not clear that the comparison is particularly meaningful, especially in comparisons between technologies of differing capital intensities. The ERG methodology inherently favors low capital-cost technologies by understating operating costs relative to capital costs.

While the methodology which ERG uses is inherently weighted against capital-intensive technologies, the values ERG uses in its analyses are generally biased in favor of capital-intensive technologies in general, and large central plants (especially nuclear units) in particular. The concept of "1979 Base Cost" excludes two cost categories which are particularly significant for nuclear plants: AFUDC and "contingencies". AFUDC is clearly a real construction cost, since it represents the accrued cost of money associated with tying up capital for a decade or more. Because of their lengthy construction schedules, nuclear units have large AFUDC components, as do other large units (e.g., coal, and probably large tidal plants). Many small scale technologies (e.g., wind, solar, small hydro, most conservation, cogeneration) will be operational within a year of less, so AFUDC on these projects will be minimal.

"Contingency", as a component of expected cost, is extremely large for nuclear power plants. Utility estimates four years prior to the scheduled on-line date are generally only about half of the eventual cost, even including all of the utility "contingency". Unless the cost of other technologies is similarly underestimated, omitting contingency biases the analysis towards nuclear plants. For existing off-the-shelf technologies, such as conservation, small hydro, and cogeneration, a 100% average cost overrun seems quite unlikely.

The ERG analysis also fails to reflect important timing differences between technologies. MMWEC does not expect Seabrook to come on line until 1985/86, a realistic assessment for Seabrook would probably be at least a few years later, and a new nuclear project (e.g., Pilgrim II) could probably not be on line much before the year 2000. On the other hand, conservation programs could be productive within a year or two, and off-the-shelf generation shortly thereafter. There are clear advantages to saving oil in the near future, which the ERG methodology can not capture.

One of the most serious errors in the ERG analysis lies in the use of a very low cost of capital for social decision-making. It is clearly absurd for one government agency (MMWEC) to justify its decisions to another agency (EFSC) on the basis of a private cost of capital. MMWEC may indeed be able to raise funds at 7.75% by offering low-risk, tax-exempt bonds, and by not paying income taxes; nonetheless, the capital is being withdrawn from the general economy where it probably has a value of 20%-30%. Thus, the ERG methodology understates the social cost of capital investment, AFUDC, and other other costs in the early years of the analysis.

Dr. Forbes' testimony also appears to minimize the value of non-base-load generation. Without ever explicitly saying so, he seems to assume that a kwh of peak energy is less valuable than a kwh of intermediate energy, which in turn is less valuable than a kwh of baseload energy. The opposite is true. It is at peak times that the most expensive oil is burned in the least efficient plants, that outages are most likely to occur, and that additional capacity is most likely to be needed. Thus, on a kwh basis, power is more valuable if it is delivered from a peaking plant (fuel cell, hydro, and to some extent solar) at peak than if it is delivered by a baseload plant (e.g., nuclear), partly on peak and partly off.

Dr. Forbes also attempts to minimize the value of certain technologies by describing them as "fuel savers" and suggesting that "backup capacity" would be required to make them reliable power producers. Since no generator is totally reliable, utilities must generally maintain some reserves if customer disconnections are to be avoided. The size of system reserve necessary varies with the composition of the generating system and the shape of the load curve, but reserves are not unique to the alternatives which Dr. Forbes discusses. Nor are the load-carrying abilities of these alternatives inconsequential. Kahn (Reliability of Wind Power from Dispersed Sites: A Preliminary Assessment, April 1978, Lawrence Berkeley Lab) found that various large California wind arrays would have effective load carrying capacities (ELCC) of between 12.4% and 26.5% of their rated capacities. Smaller arrays have higher ELCC's. This compares well with typical capacity factors for wind machines (Kahn's study was based on 24 mph rated wind speed) of about 30%. Large nuclear plants, with ELCC's of about one half rated capacity, and 60% capacity factors, deliver somewhat more firm capacity than wind machines, but not overwhelmingly so; nuclear plants provide about .85 firm MW per average MW, while wind arrays provide about .6-.7. Peaking hydro units may provide well over one firm MW per average MW. Whatever value is attached to firm capacity can be credited to all generators (and to conservation) to the extent they provide firm capacity; nuclear would receive a larger credit than some alternatives, and a smaller credit than others. In any case, no generator requires specific additional "backup capacity" or storage.

The preceding discussion is not very relevant to New England in the foreseeable future. Since NEPOOL has a large reserve margin, the value of additional firm capacity is not very large. If new capacity were needed solely for reliability, relatively cheap gas turbines and pumped storage facilities would be the obvious choices. In any case, the contribution of ELCC to the total value of a generator is not likely to be important.

Q: Please explain why the nuclear costs utilized in Dr. Forbes' analysis are too low.

A: Dr. Forbes understated social carrying costs and neglects AFUDC and "contingency" as discussed above. His capital cost estimates are far too low for Seabrook, partly due to the errors described above. His estimate of O & M is also too low, and he ignores interim replacements, presumably because he uses MMWEC cost estimates as the basis of his analysis. Finally, his capacity factor estimates are too high.

Q: What are reasonable 1979 dollar capital cost estimates for Seabrook?

A: The NERA-based and Rand-based cost estimates in my D.P.U. 20248 testimony can be converted to 1979 dollars by removing 10% inflation for 4 years for all estimates and 8% inflation for 1.5 years for January 1985 inservice dates, 3.33 years for November 1986 and 7.33 years for November 1990. This adjustment produces the values given in Table 1. As indicated in my D.P.U. 20248 testimony, the 1985/86 schedule is quite optimistic. The 1985/90 schedule is a more reasonable prediction, based on past trends.

Plant/date	Method NERA	Method Rand
a. Seabrook 1, 1985	$1736/kw	1513
b. Seabrook 2, 1986	1579	1500
c. average, a & b	1658	1507
d. Seabrook 2, 1990	2312	1534
e. average a & d	2024	1524

Table 1 Estimates of Seabrook Costs, in constant 1979 $/kw

Q: What would a reasonable range be for projections of Seabrook O & M costs?

A: In my D.P.U. 20248 testimony, I develop estimates of $73.7 million to $450.1 million in constant 1985 dollars, as average O & M cost values. From Dr. Forbes' observation that MMWEC's cost of capital is approximately the same as the inflation rate, the average real cost will equal the levelized real cost (Under a social-cost analysis, the levelized cost would be smaller, but capital costs and carrying changes would be larger). To convert these values to 1979 dollars, it is necessary to divide by

$$1.1^4 \times 1.08^2 = 1.71,$$

which yields $43.2 to $263.6 million, or $37.6/kw to $229.2/kw.

Q: What would a reasonable expectation be for annual additions to capital cost?

A: In my D.P.U. 20248 testimony, I derived a cost of $11.4/kw in 1979 dollars. MMWEC's approach indicated that a 3.9% to 4.2% carrying charge would be necessary (depending on whether one accepts MMWEC's data with or without my additions).

Q: How do these costs convert to ¢/kwh in 1979 dollars?

A: As I explained in my D.P.U. testimony, a 60% capacity factor is about as good as one can expect from Seabrook size nuclear units. The 67.8% value the Dr. Forbes uses is clearly too high. Using the 12% carrying charge MMWEC assumes, the cost per kw-year is

(1500 to 2024) x .12 = 180 to 242.9 for initial capital cost

37.6 to 229.2 for O & M

11.4 for capital additions

if my approach is used or

(1500 to 2024) x (.039 to .042)

= 58.5 to 85.0 for capital additions

if MMWEC's approach is used, for a total of \$219.0/kw to \$557.1/kw. At a 60% capacity factor, this is equivalent to 4.2¢/kwh to 10.6¢/kwh. Because of the inconsistencies in ERG's methodology, these prices are not really comparable to one another. About 0.9¢ (22%) of the low-end figure (4.2¢/kwh) is O & M and capital additions, which rise with inflation. For the high-end figure (10.6¢/kwh, which is not an extreme estimate, since the schedule is not conservative and no TMI-related effects are incorporated), about 4.4¢/kwh (41%), all in O & M, rises with inflation. This compares to ERG's estimate of 2.02-2.04 ¢/kwh for the same cost elements, with only 0.19¢/kwh of O & M subject to inflation. Adding in ERG's estimate of 0.77¢/kwh for fuel and decommissioning (decommissioning would appear to be about 0.02¢/kwh higher than ERG's figures, even given Mr. LeMaster's estimates, but the difference is not very significant compared to O & M and capital cost uncertainty), reasonable estimates for Seabrook power costs would run about 5.0-11.4¢/kwh; with 34%-46% of the total subject to inflation.

Q: If Seabrook is as expensive as the historical trends presented in your D.P.U. 20248 testimony would indicate, are there cheaper ways to generate power or reduce demand?

A: Yes. There appears to be a large number of such techniques, including conservation techniques on customers' premises, conservation techniques applied on the utility system, non-electrical energy production technologies, and electrical generating techniques. A few of these are discussed below.

In addition, there exist techniques for saving oil in existing generating facilities. If reduction of dependency on imported oil is a primary concern to MMWEC it might more cost-effective to participate in conversion of existing generation facilities to wood or coal firing, to combined cycle operation or to cogeneration either instead of or in addition to expanding its nuclear programs. Indeed, from the viewpoint of a town, the Commonwealth , or the region, it would be more cost-effective to save oil by insulating oil-heated structures than by building Seabrook, or especially additional nuclear plants.

Q: Are conservation and load management techniques equivalent to providing similar amounts of energy and capacity through construction of new generators?

A: No. In general, the conservation and load management techniques are superior. New England is unlikely ever to experience the rapid loss of 1000 MW of conservation (insulation, for example), but 1000 MW of Seabrook will frequently become unavailable, quite quickly and with little warning. Increased motor efficiency can not be disconnected from demand by a transmission failure; central generators can. Most conservation procedures become effective soon after funds are expended on them; a new nuclear unit would be under construction for well over a decade before it starts to reduce oil use.

Q: Are there conservation techniques which will save energy for less than the cost of producing new energy through construction of nuclear capacity?

A: Yes. Assuming the MMWEC cost of capital which Dr. Forbes uses in his testimony, and a 40 year life, adding 9 inches of loose cellulose on top of six inches of existing fiberglass attic insulation saves electricity at around 4¢ to 5¢ per kwh (1979$) in various portions of Massachusetts. These nine additional inches of insulation would typically save about 1600 kwh/year for a house with 1200 sq. ft. of ceiling. Smaller amounts are even more cost effective; for example, four inches of added insulation costs only about 3¢/kwh saved.

Using a DOE estimate of 400 kwh/year savings from water heater tank insulation, current retail price of $15 for ready-made insulation and a fixed charge rate of 18% (pessimistically assuming a short 10-year life of the water heater and its insulation, and application of property tax), it costs only 0.7¢/kwh to save electricity by insulating existing water heaters. If one accepts DOE's estimate of less than $5 for insulation and tape, the cost is about 0.2¢/kwh.

Q: Are there other promising conservation techniques which are more consistent with traditional utility activities?

A: Yes. Such techniques include rate reform, conversion of master-metered apartments and businesses to individual meters, and voltage control.

Q: Please describe how rate reform can result in energy conservation.

A: It is well established, on theoretical, practical, and empirical grounds, that consumption of electricity is primarily responsive to the marginal price of electricity, rather than customer charges or other intra-marginal charges. Raising the tail block price by 10% should reduce sales by some 8% over the next decade or so at no cost to the utility and, if intra-marginal costs are similarly reduced, without increasing (in fact, reducing) customers' electric bills. As long as the marginal rates charged to customers for electrical energy are below the real costs of building and operating the facilities necessary to provide that energy, customers are being encouraged to waste energy and discouraged from implementing conservation measures which are cheaper than the new capacity. Yet most of MMWEC's members have declining block rates for most or all of the major rate classifications. Since municipal light plants can return over-collections to the municipality (for example, in-lieu-of-tax payments), it is even easier for MMWEC's members to adopt marginal-cost pricing than it is for privately owned utilities.

Energy use can also be reduced by collecting industrial and commercial revenues through energy charges, which encourage conservation, rather than demand charges, which primarily encourage shifting of loads (but not necessarily off of system peak). If system costs vary considerably by time of day, time-differentiated energy rates can reflect this variation, and encourage appropriate levels of conservation at all times; demand charges cannot do this. Yet many of MMWEC's members retain demand charges for large customers and apparently none of them have instituted mandatory time-of-use rates.

Many of MMWEC's members also offer lower, promotional rates for selected uses, especially residential heating, but also on some commercial and industrial rates and sometimes for air conditioning, water heating, and other uses in electrically heated buildings. These rates simply increase the subsidy for these uses, which is undesirable for three reasons. First, end uses such as water heating and space heating, for which alternative energy sources exist, are probably more price sensitive than non-competitive uses such as lighting and motors. Second, large efficiency improvements are possible in space conditioning and water heating, which will not be adequately pursued under promotional rates. For both these reasons, promotional space conditioning and water heating rates will tend to increase total electric use. Third, using electricity for space heating is very inefficient; about three times as much fossil fuel is used in heating a house electrically as would be necessary to heat the same house directly. For heating water, electricity uses between two and three times as much fuel as does direct firing. While there may be some advantage to burning #6 oil in utility boilers rather than #2 oil or natural gas on customers' premises, it is not likely to exceed this sizable efficiency penalty. Therefore, the extra subsidies of electric heat and related uses which are offered MMWEC's members increase electric use in a particularly undesirable way.

Q: What are the advantages of preventing new master-metering installations and converting existing installations to individual meters?

A: The master-metered electricity user essentially faces a zero price of energy, and therefore has no incentive to use it wisely. Any connection between the behavior of the master-metered user and the costs to that user is quite tenuous. Under direct utility metering, submetering (in which the building pays the utility, and the occupants are billed by the building), or check-metering (in which the building bill in simply apportioned to the occupants in proportion to their kwh consumption) the electricity consumer can save money by saving energy.

Consumers do seem to respond to direct metering. Federal Energy Administration figures (UCAN Manual of Conservation Measures, Conservation Paper #35) indicate that single-metered apartments use about 25% less energy than master-metered apartments; Boston Edison data indicates that single-metered apartments use only about half the heating energy of master-metered units. A recent submetering conversion in New York appears to have reduced occupant electric consumption by 35% (<u>Electrical Week</u>, 5/2/80, p. 6).

It is not possible to calculate MMWEC's potential savings from the elimination of master metering, since

MMWEC has not even bothered to collect information on the number and usage of master-metered apartments and businesses, let alone study the economics of converting them.

Of course, if all electric customers were charged the full cost of producing additional electricity and supplying it to them, the owners of master-metered residential (and commercial) facilities would have a greater incentive to convert their own units.

Q: Please describe the potential energy savings and costs of voltage control.

A: Results to date indicate that it is very attractive. In one study, American Electric Power reduced voltage for only 4 hours a day; the experiment showed savings of only 0.54%, including some circuits for which there were negative savings. (Electrical World, 6/15/77, pp. 52-53) The cost of applying a control system (apparently more flexible than that used in the experiment) to the entire AEP system was estimated to run into the "tens of millions" of dollars. Taking a series of worst-case assumptions, including AEP's short and fixed Q21 charge rate of 14% (MMWEC's cost of capital, 15 year life), we get a cost per kwh saved of 4.1¢.

Results from Southern California Edison indicate that continuous reduction of voltage by only 2-3% can save 2% to 6% of sales (and demand), with positive savings on all lines; this is consistent with AEP's results during the 4-hour period of actual voltage reduction. Combining these results with the other data above yields a cost estimate per kwh saved of 0.4¢ to 1.1¢. If MMWEC's forecast 1988 retail output (4678 GWH) is reduced 4.0%, it would save 187 GWH, equivalent to 36 MW of Seabrook output.

Voltage Control

Q: Can cogeneration replace oil-fired capacity at a lower cost than Seabrook capacity?

A: It would appear so. The Final Report of the Governor's Commission on Congeneration (Cogeneration: Its Benefits to New England, October, 1978) gives cost estimates for numerous combinations of cogneration technologies, heat demands, and capacity factors. These cost estimates include capital costs, O & M, and data from which heat rates can be calculated. Somewhat higher (but less specific) estimates of capital costs and heat rates are given in an article entitled "Cogeneration" (Power Engineering, March, 1978, pp. 34-42). While there are some complications in analyzing the cost of replacing inefficient conventional oil-fired generation with efficient oil-fired cogeneration, the task is not insurmountable.

For example, for an 11 MW steam turbine to be run at 80% capacity factor, the Governor's Commission reports $450/kw capital cost, 0.1¢/kwh O & M, and a heat rate of

4417 BTU/kwh. For steam turbines in general, Power Engineering estimates 5000 BTU/kwh and $500-$600/kw. The 230 kVa cogenerator being installed at Middlebury College in Vermont will cost $50,000 (or about $250/kw), in addition to some installation costs which are not separable from other efficiency improvements.

check

A marginal heat rate for conventional steam plants of around 10,000-11,000 BTU/kwh implies that the cogenerator would use only 40-50% as much fuel as conventional plants to produce a kwh. Stated differently, for every kwh a conventional plant produces, the cogenerator can create 2 to 2.5, essentially getting 1 to 1.5 free kwhs for each kwh produced at conventional heat rates. Therefore, an 80% cogeneration capacity factor can be interpreted as 32% to 40% capacity factor at conventional heat rates and 40-48% capacity factor at a free heat rate. In order to eliminate the price of oil from the cost of cogeneration, it is useful to examine only the capacity factor from the "free" generation, net of equivalent conventional oil generation.

Table 2 presents the cost of cogenerated electricity from large steam plants under various assumptions regarding capital cost and heat rate. The highest capital cost, $600/kw, appears to refer to smaller plants, on the order of 3 MW, but it is included for comprehensiveness. As the Middlebury experience indicates, small cogenerators on existing steam systems can be even cheaper. The kwhs generated at the conventional heat rate are assumed to cost about as much as conventional running costs; of course, there are additional savings compared to the fraction of marginal generation which burns #2 oil, and there may be lower losses, since the cogenerator will almost certainly be located close to the load it serves, including the facilities which use its heat, so this assumption is conservative.

Escalating these costs 11% to 1979 dollars yields costs of 3.8¢ to 6.0¢/kwh. Since only the O & M fraction of the cost escalates after the plant goes on line, this cost is quite stable over time, so long as oil is the marginal fuel for New England, rising only about .5¢/kwh to the year 2000.

Even under the worst-case assumptions, this installation would provide electricity for much lower cost than would Seabrook. In addition, its small size, high reliability, and dispersed siting would give the cogenerator a much greater contribution to reliability than a similar amount of nuclear capacity (per kw or per kwh); the dispersed siting will actually provide improved local reliability regardless of the amount of total generation available in New England.

To the extent that cheaper, non-oil fuels (coal, wood, waste) can be utilized in the cogenerator, the costs can be even lower, depending on the additional costs of handling the fuel and its by-products.

Q: Is solar space heating and water heating competitive with power from new nuclear units?

A: Several studies which were not conducted by utilities have concluded that solar thermal energy is now competitive with electricity, or soon will be. For example, the President's Domestic Policy Review of Solar Energy (February, 1979) concluded that solar water heating will be cheaper than electricity by 1985, and that passive space heating already is cheaper. The cost of electricity used in the study is considerably less than the delivered cost of Seabrook power, as I have calculated it, while the estimated 1985 cost of solar water heating converts to less than 4.1¢/kwh for the Northeast, that of active solar space heat converts
5.5
to 4.1-5¢/kwh nationally, and that of solar cooling to 5.5-6.8¢/kwh nationally.

These conclusions are supported, at least qualitatively, by an NSF study (Solar Heating and Cooling: An Economic Assessment, McGarity, A.F., 1975), an ERDA study (An Economic Analysis of Solar Water and Space Heating, DSE-2322-1, November, 1976), and an OTA study (Application of Solar Technology to Today's Energy Needs, June, 1978).

In fact, even the NEES solar water heater report indicates costs to MMWEC of about 6.9¢ to 11.0¢/kwh saved (with about 20% subject to inflation), depending on the type of system, and on the exact distribution of the better systems. These figures are based on 1976 technology, which is now obsolete, and ground mounting.

Q: Does this conclude your testimony?

A: Yes.