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COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF PUBLIC UTILITIES

D.P.U. 535

Regulations proposed by the Department of PUblic Utilities, to establish rules by which a rate or rates may be calculated for sale of electrical energy by small power producers or cogenerators to electric utility companies under the Department's ratemaking jurisdiction; and other rules determined necessary to carry out the purposed of the Public Utility Regulatory Policies ACt of 1978 ("PURPA"), Title II, Sections 201 and 210.

Testimony of
Paul Chernick
on Behalf of
the Attorney General

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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.

A: 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 Optimal Pricing for Peak Loads and Joint Production: Theory and Applications to Diverse Conditions, Report 77-1, Technology and Policy Program, Massachusetts Institute of Technology. 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. 19494, Phase I. I have also testified jointly with Susan Geller in Phase II of D.P.U. 19494, concerning the forecastws of nine New England Utilities and NEPOOL, and joijntl 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 proceedings 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 Geneerating 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; in PUCT 3298, on Gulf States Utilities' Texas retail rate design; in EFSC 79-33 on EUA's 1979 forecast and supply plan; in EFSC 79-1 on MMWEC's 1979 supply plan; and in D.P.U. 472 on the allocation of the costs of the Residential Conservation Service. 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.

General Comments

Q: Do you have any general comments on the format and clarity of the proposed regulations?

A: Yes. While the regulations are generally quite clear, some confusion may result from two types of omissions. First, it is often not clear that various requirements refer only to standard rates, and that different rates and terms can always be fixed by contract. It would be helpful to clarify this point.

Second, the intent of the regulations is sometimes obscured by the absence of mathematical formulae or their precise verbal counterparts. For example, the last sentence of the second paragraph in section IICla could be read as requiring calculation of the average cost per kwh at various load levels, and the payment of the differences. I am quite sure that the proposed regulations are intended to mean that the difference in total cost between the load levels is to be divided by the difference in load, to derive the avoided energy cost. In other words, the language could be read to mean

$$A = C_{100}/L_{100} - C_{90}/L_{90},$$

a formula completely unrelated to avoided cost, when it is supposed to mean

$$A=(C_{100}-C_{90})/(L_{100}-L_{90})$$

Where C_x= Cost at x% of expected load

L_x= Kwh sales at x% of expected load

A = Avoided fuel and O&M cost

In general, formulas are superior in clarity to verbal description. A reasonably clear verbal form of the second interpretation above might read "the avoided cost in cents per kwh shall be the quotient of

a. the difference between the total cost at 100% of expected load and the total cost at 90% of expected load, divided by

b. ten percent of sales at the expected load."

However the calculations are described, the algorithm should be clear, to avoid subsequent problems in interpretation. The quarterly rate-setting process envisioned by the proposed regulations will be difficult enough even without any arguments over the intent of the regulations.

Section I

Q: Do you have any comments on section I of the proposed regulations?

A: Yes. I believe that the DPU should make the following changes in this section:

1. expand the filing requirement for a QF in providing notice to a utility;

2. limit the utility's ability to require FERC or DPU certification of a QF to those situations in which the utility may have a legitimate concern regarding the facility's status;

3. explicitly describe the process of certification for existing facilities;

4. exclude the current power production of large existing facilities from the rate-related benefits of QF status, but expand QF status to additional facilities;

5. list the utilities covered by the regulations;

6. explain which utilities must buy from which QF's, and

7. establish procedures for reviewing contracts between QF's and utilities.

Q: In what ways should the filing requirement for QF's be expanded, and why?

A: It seems appropriate to require potential QF's to provide the utility with the same data that would be required in an application for FERC certification, as well as any detailed projections of output patterns available to the facility. The advantages of this expanded filing are three-fold.

First, the expanded information, such as facility size, technology, and fuel type will be useful to the utility, to the DPU, and to other regulatory and planning agencies (e.g., the EFSC, the MEOER) in assessing system reliability, the sensitivity of energy adequacy to weather conditions, fuel availability, and so on; and in determining the value to the utility of various supply options, such as transmission lines and energy storage facilities.

Second, this information should provide a basis for initiating the interconnection process. I will discuss this aspect later.

Third, the utility should be able to determine from this information whether there is any reason to doubt that the facility is eligible to be a QF. Hence, the certification process could generally be waived.

Q: Exactly what information should be included in the notification of intention to interconnect?

A: The Attorney General's post-hearing comments in this docket will include a proposed restatement of the regulations. For the most part, the suggested language would simply paraphrase or quote §292.207 (b) of the FERC regulations.

Q: Why should the broad right of the utility to require FERC certification, as provided in the proposed regulations, be limited?

A: In most cases, there will be no question regarding the qualifying status of the facility. Unless the utility has some reason to believe that the facility is not a QF, there is no point in involving FERC or the DPU in the certification process. Any utility should be able to read a notification of intent to interconnect and determine whether any problem exists within thirty days of receipt. If a utility questions the QF status of the facility, it shoud be required to state the reasons for its doubts on a letter to the QF with a copy to the D.P.U. Only then should the QF have to seek certification. The D.P.U. should also attempt to discourage frivolousa challenges by utilities.

Q: How should section IB of the proposed regulations be clarified?

A: The DPU should indicate that it will play the role otherwise taken by FERC in certifying these facilities, where necessary. The application and certification process should be identical to the FERC process, and the regulations should make this clear.

Q: How should the criteria for qualification in section IB be changed?

A: If an existing facility has been producing power in exchange for a rate less than that offered to QF's, and there is no reason to believe that it will not continue doing so, it is unnecessarily expensive to the consumer to pay the facility the higher QF rate. These existing facilities will not generally require the standard rate, or any PURPA-derived rate, to encourage production, which is the purpose of PURPA §210. Existing facilities should be eligible for avoided cost rates, including standard rates, only for

a. production in excess of 1977-1979 average levels, since that excess was apparently not encouraged by existing arrangements;

b. production from additional equipment within the facility;

c. production from existing facilities of less than 100 kw, which inherently lack sufficient bargaining power to receive fair rates, and must have been developed in the public interest or in expectation of regulatory reform, as accomplished by PURPA, and

d. production which the facility can demonstrate to the DPU would not occur under the existing arrangements.

Point (a) would ensure that very recently developed facilities, which may have been built in expectation of PURPA-type reforms would be eligible for avoided-cost rates for most or all of their output. These provisions should provide avoided-cost rates to existing facilities which need them, without unnecessarily increasing the cost to consumers or creating windfall profits.

The regulations should also extend QF status (for intra-state purposes) to facilities which fail to meet FERC's definition of small power producer because they use too much gas, oil, or coal. It would be very wasteful not to take advantage of any small coal-fired units which may already exist, or be feasible to develop. Facilities which are built to burn trash with coal backup, for example, should be able to operate with over 25% coal input without being disqualified. If it is economical to build and run a waste burning facility on a higher percentage of coal input, either to capture economies of scale or to provide for seasonal variation and long term growth in waste supplies, the development should not be discouraged by the absence of rights to interconnection and fair rates. Similarly, experimental fossil-fueled facilities (Magnetohydrodynamics, fuel cells, fluidized beds, superconducting generators, etc.), which may be able to operate at lower costs than the utility, should be encouraged to do so. Providing QF status to high-efficiency fossil-fired facilities may encourage siting of more development work in the Commonwealth, and will tend to increase the power produced by these innovative devices. On the other hand, it is unlikely that anyone will choose to build a conventional, non-cogenerating plant of under 80 MW fueled by oil or gas, since it would not be profitable under avoided-cost pricing.

Q: Which utilities should be covered by the regulations?

A: As I understand it, there are nine utilities which are primarily retail utilities and are clearly regulated by the DPU:

1. Boston Edison Company (BECO)
2. Western Massachusetts Electric Company (WMECO)
3. Massachusetts Electric Company (MECO)
4. Eastern Edison Company (EECO)
5. Fitchburg Gas and Electric Company (FGE)
6. Manchester Electric Company
7. Nantucket Electric Company
8. Cambridge Electric Light Company (CELCO)
9. New Bedford Edison Light Company (NBE)

However, since the last two are treated as part of a single NEPOOL participant (NEGEA), and since the proposed regulations are apparently attempting to mimic NEPEX billing, it is appropriate to use the same basic costs for both CELCO and NBE. Only losses and area-protection costs will vary from one part of NEGEA's service territory to another; these factors will be discussed below, since they apply to several utilities.

In addition to the eight primarily retail utilities, the DPU also must implement the rules prescribed by PURPA §210 and by the FERC regulations with regard to New England

Power Company (NEPCO). NEPCO has some retail sales in the Commonwealth, and while the DPU has not generally chosen to exercise its authority regarding these contractual sales, it definitely "has ratemaking authority" over NEPCO's retail sales. PURPA §210(f)(1) requires that

> "each State regulatory authority shall, after notice and opportunity for public hearing, implement [FERC's cogeneration and Small Power Production Rules] for each electric utility for which it has ratemaking authority."

Thus, the DPU <u>must</u> set avoided-cost rates for sales from QF's to NEPCO, as well as applying the rules on interconnections, backup rates, and so forth required by the FERC regulations.

Q: Which utilities should be required to purchase power from a particular QF?

A: A utility should be required to purchase power from any QF which

a. is located in the utility's retail service territory,

b. is willing to provide or pay for an interconnection with an appropriate facility of the utility (e.g., a transmission line, distribution line, or substation), or

c. provides power to the transmission or distribution system of any wholesale customer (excluding contract demands and unit sales) of the utility.

The last provision recognizes the fact that a QF in Concord (a BECO wholesale all-requirements customer) will displace BECO generation costs in exactly the same way as a similar QF in Lexington. This provision is particularly important in allowing direct sales to NEPCo from MECo and Manchester service territories.

Q: Should the DPU make any provisions in the regulations to facilitate the review and implementation of special contracts between QF's and utilities?

A: Yes. A formal procedure for the review and approval of contracts would probably be helpful. The D.P.U. should establish amonitoring program to prevent the approval of anticompetitive agreements, excessive payments to QF's, and other potential problems.

Section II - Energy

Q: Do the proposed regulations use the proper basis for setting energy rates?

A: No. The proposed regulations base energy rates on an entirely fictitious premise that each utility company dispatches its own plants (including tiny fractions of jointly owned plants and unit sales) to meet its own load. In fact, NEPOOL actually dispatches all the capacity in mainland New England to meet total New England load. It follows that the basis of energy rates should be the NEPOOL marginal energy cost, that is, system lambda. This is true both (a) in the economic sense and (b) in the context of the FERC rules. The alternative measure of energy cost in the proposed regulations would produce prices which would be (c) inefficient, (d) untimely, (e) unwieldy, (f) administratively complex, and (g) less appropriate for Massachusetts. The utilities will not suffer under NEPOOL-based pricing, due to protection from (h) the FERC regulations and (i) NEPOOL billing procedures. Each of the points listed is discussed at greater length below.

a. There is only one utility which supplies bulk power, dispatches plants, and determines flows on transmission lines in mainland Massachusetts, and that is NEPOOL. As a general rule, the response to a load decrease due to a QF will be determined by conditions in the NEPOOL system. That response will be the backing down of the most expensive unit running in NEPOOL, hence, the true avoided cost is a NEPOOL cost. It also follows that the basis avoided energy cost must be the same throughout New England, since all utilities <u>in fact</u> use the same set of plants.

b. NEPOOL performs most of the functions which the operating utility would normally perform and which determine the avoided cost. These functions include central dispatch; scheduling of hydro units, pumping for storage hydro, and similar energy-shifting supply management procedures; coordinating transmission flows; maintaining operating reserves; providing local generation protection; scheduling maintenance of generators and trasmission lines; responding to capacity and energy emergencies, including determining when voltage reductions, customer disconnections, and other techniques should be applied; forecasting demand; determining required reserve levels; and to some extent, planning transmission and generation additions. Therefore, the nature of costs which are avoided due to the operation of a small power producer are determined by conditions on the NEPOOL system. Further, since the FERC regulations and discussion clearly consider "the utility" to be the entity which dispatches load, experiences system emergencies, plans generating additions, and so on, it is clear that "the utility" in this context must be NEPOOL.

c. The proposed alternative to a NEPOOL-based purchase rate is a set of company-specific rates, based on an own-load dispatch model with corrections for NEPOOL savings shares. Such an alternative has several disadvantages, beyond the inefficiency which would result from not using the true avoided cost for New England. First, company-specific rates would produce absurd situations in which two neighboring facilities located in different utilities' service territories are offered substantially different rates at the same time. A winter-peaking utility may be running gas turbines on its theoretical own-load dispatch at the same time that an adjacent summer-peaking utility is operating only base-load plants. The true avoided cost may be that of an intermediate unit elsewhere on the NEPOOL system; the QF in the winterpeaking territory would be overpaid, and that in the summer-peaking territory would be underpaid.

d. The utilities have indicated that an estimate of actual avoided cost under own-load dispatch would only be available with a delay of some six weeks. Any hope of encouraging large QF's (trash burners, hydro plants with storage, cogenerators, wood and geothermal plants) to respond in real time to system conditions (load, plant outages) would be lost. There would be no extra incentives for operators to increase their output in times of high actual demand. With an instantaneous incentive (such as NEPOOL actual avoided cost), larger QF's could be notified when their power was most valuable, and could increase their revenue and their usefulness by increasing output at those times. The proposed regulations, based on the fictitious own-load dispatch, do not even envision any useful real-time incentives.

e. The theoretical own-load cost measures are also extremely unwieldy. Since the actual values cannot be determined in any reasonable time frame, it would be necessary to project own-load dispatch costs for each company, producing nine separate forecasts for the various private Massachusetts utilities, and nearly fifty forecasts for the state as a whole. Some sort of reconciliation mechanism would also be necessary; given the seasonal nature of many QF's production, a fair reconciliation will be difficult to administer, especially given the large number of systems involved. (The reconciliation problem, which is ignored by the proposed regulations, will be discussed in a subsequent section of my testimony.)

f. Own-load dispatch pricing of purchases from QF's would also create the need and desire for QF's to sell to specific utilities with higher calculated avoided costs. Hence, generators may be located in non-optimal areas, expensive and unnecessary tielines may be built, QF's will need to sell directly to wholesalers in order to function profitably, and QF's will want to wheel their power to different utilities over time. Potentially, a QF could wind up dealing with virtually every utility in New England over the course of time. In addition, the own-load purchase rates for the private electric companies would not provide any useful guidance to the dozens of municipal electric utilities in the state. NEPOOL-dispatch pricing would eliminate the need for separate wheeling calculations and arrangements, would make QF's indifferent between utilities, would encourage efficient and economical siting and interconnections, and would provide a convenient and relevant basis for the design of municipal QF rates.

g. Even if the DPU would prefer to limit the calculation of avoided cost to the Massachusetts avoided cost, rather than the New England avoided cost, the NEPOOL system lambda is the best available proxy. Massachusetts is approximately 42% of NEPOOL; costs to Massachusetts utilities are very closely linked to those in other states through the wholesale rates of NEPCO and Montaup, and through NU's internal dispatch. Hence, the pattern of costs and savings to Massachusetts will tend to resemble that of NEPOOL as a whole; reductions in NEPOOL costs are likely to reduce costs to Massachusetts consumers. On the other hand, individual company costs (based on NEPOOL billing and own-load dispatch) may have little relevance to Massachusetts costs. BECO's theoretical own-load marginal cost may be nuclear at some times, due to the presence on BECO's system of must-run oil units, while every other utility in the Commonwealth is being billed for oil generation. Under own-load pricing, cogenerators in BECO's territory will not run, even though they would have reduced the use of oil in Massachusetts (and New England).

h. The FERC regulations (§292.303d) provide that the utility which would normally purchase energy or capacity from a QF may transmit that energy or capacity to a second utility, which must then pay its avoided cost. No wheeling charges are permitted. Thus, the Massachusetts utility which is directly connected to the QF can wheel the power to the utility (or utilities) which otherwise would pay the NEPOOL system lambda, and should receive full payment from the latter. The mechanism for actual billing and crediting between utilities may be left to NEPOOL, its members, and FERC, in whose jurisdiction the enforcement of this aspect of the regulation must lie. Since the substantial majority of voting power in NEPOOL is held by utilities doing business in Massachusetts, the development of the compensation mechanism should proceed quickly enough to protect the interests of those utilities.

i. It appears that current NEPOOL billing arrangements are sufficient to ensure that utilities which compensate QF's at NEPOOL lambda will not be penalized. A net supplier to the pool is paid its incremental cost for all power in excess of its own needs; any additional cost above the own-load dispatch cost is paid by the pool. Thus, any additional cost due to pricing of QF power on the net seller's system at NEPOOL cost would be paid from the pool. The net seller would also receive an extra saving share for each kwh provided by the QF. A net buyer, on the other hand, must pay to the pool the cost of the plants hich would have run, if not for the existence of the pool. Each kwh supplied by a QF eliminates the need for the most expensive kwh of own-load energy; this avoided cost must be higher than pool lambda (and hence the price paid the

QF), or else the buyer's plant would have run. The buyer may also avoid paying for more expensive classes of pool power, such as unscheduled outage or deficiency. While the net buyer does lose a savings share, this is very likely to be smaller than the difference between the price paid to the QF and the own-load marginal cost. Thus, there should be no additional cost to Massachusetts utilities due to their unilateral use of NEPOOL's marginal cost as the basis of purchase rates.

NEPOOL's system lambda actually will be too low to meet FERC's requirement that avoided costs include "The individual and aggregate value of energy and capacity from qualifying facilities on the electric utility's system" (§242.304(e)(2)(VI). The aggregate value of energy from QF's will include both the current system lambda and the higher incremental costs which would result if some of the QF's went off line. Hence, the average value of the QF's will generally be greater than the value of the last kw. There does not seem to be any easy way around this problem, without incurring the costs and delays of hypothetical redispatch. However, a simple compromise is possible. Annual or quarterly simulation runs can be performed to determine the average difference or ratio between aggregate avoided cost and marginal running costs, and the resultant corrections can be applied to all purchases in the period. NEPOOL is a larger and more stable system than individual companies, in terms of both supply and demand, so that the variations in and between marginal cost and avoided cost will tend to be smaller for NEPOOL.

Q: Is it feasible to precisely model NEPOOL billing as the basis for purchase rates?

A: No. NEPOOL's billing (as explained in the NERCOMM report attached as Appendix 2) is too complex and subjective to be the basis of any actual rates. NEPOOL's energy exchange includes, in addition to the economy exchange which produces the saving share incorporated in the proposed rules,

1. Scheduled outage power, the cost of which is levelized over the year by the use of a "loaden" added to the cost of the plant on scheduled outage;

2. Unscheduled outage power, for which the recipient pays the cost of the plant which did not run, or of the plants which replaced it, whichever is more expensive;

3. Deficiency power, for which a 10% premium is charged.

Each class of power is provided from successively more expensive plants, and none but economy contribute to the savings fund. In addition, there is billing and crediting for operating reserve provided to or by the pool, and this transaction earns savings shares.

NEPOOL's own-load dispatch of its members for billing purposes is a peculiar process which apparently assumes no outages, scheduled or otherwise. Outages are handled by assessing different replacement power costs to the plants, rather than by dispatching the owner's other plants. However, NEPOOL staff must make numerous subjective judgment concerning the availability of particular plants. NEPOOL must decide which units to run, which to leave in operating reserve, which to bring up to warm standby, when to run conventional hydro, when and how much to pump up storage hydro, when to release it. NEPOOL apparently attempts a realistic own-load dispatch, not an optimal dispatch with perfect hindsight. As a result, NEPOOL staff must judge whether the utility staff would have been sufficiently prescient to warm up the old steam plant on Monday afternoon to meet the cold front which was due to pass through Tuesday morning, and whether the utility would have saved some hydro energy in case Wednesday was colder.

In addition, the availability of units for own-load dispatch affects the rate at which pool power is provided. Recall that the cheapest power is used to replace plants which could have run, while more expensive power is allocated to replace plants on scheduled and unscheduled outages. This aspect of NEPOOL billing requires more judgments, such as whether a problem-ridden old plant would have operated if it had been called on; whether a nuclear unit would have been on scheduled outage at the utility's annual peak, if not for NEPOOL-level maintenance scheduling problems; and whether a gas turbine would have been on unscheduled outage, if it had not been used to meet NEPOOL loads the previous week.

While the purchased power rate developed from own-load dispatch would generally be independent of the particular plants which are actually run by the utility, the sign of the correction for NEPOOL savings shares depends on whether the utility is a net buyer or net seller for the hour. A net seller receives one more savings share for each MWH provided by a QF, while a net buyer loses one savings share per MWH generated by a QF. In September, 1980, a savings share was worth $2.45, so the difference between the own-load marginal costs of buyers and sellers with the same marginal units is about 5 mills/kwh. A fairly small error in NEPOOL's determination of actual plant output (apparently a common occurrence) could transfer a utility from buying to selling status, and change the purchase rate by 0.5¢/kwh, plus losses.

Thus, the review of purchase rates for QF's, if those rates are based on own-load dispatch and NEPOOL billing procedures, will involve:

a. determining whether the utility has made any errors in translating NEPOOL billing data into rates;

b. determining whether NEPOOL has made any errors in its billing data for the utility, including checking the utility's total load, and the availability, operating status, actual output, and hypothetical own-load output for each plant or entitlement in each hour of the period;

c. checking the judgments on which the own-load dispatch was based;

d. if errors in fact or judgment are detected or suspected in NEPOOL's work, determining whether NEPOOL is willing to change its billing to the utility, to document its work, and/or provide witnesses for DPU hearings;

e. if NEPOOL will not correct its errors, determining whether the utility should pay QF's on the basis of the NEPOOL billing or on the basis of a correct billing;

f. reconciling purchase rates for past periods (potentially several such periods) for corrections in NEPOOL billings, updates in savings share value estimates, and revisions in the scheduled outage loader; and

g. projecting the purchase rate for the next period (probably a quarter) based on own load dispatch as it is expected to be performed by NEPOOL, on the expected status of the utility as buyer or seller, and on the expected size of saving shares, all of which in turn depend on future fuel prices (including non-marginal fuels, such as coal and uranium, which influence the size of saving shares), maintenance schedules, and unit availability.

Since these hypothetical-own-load-based rates would be calculated separately for at least six utilities (BECO, WMECO, NEPCO, Fitchburg, NEGEA, and Montaup), the administrative burden of this scheme would be enormous. This is particularly true if NEPOOL is not cooperative in explaining the own-load dispatch procedure and in correcting errors in monitoring actual output and loads; in this situation, a company's filing may be totally unreviewable. NEPOOL has not generally been eager to explain its procedures, or even to formalize them in written form, so cooperation is not likely.

Thus, the authors of the proposed regulations were well-advised not to try to precisely mimic NEPOOL's billing in the design of the purchase rate. Unfortunately, the proposed rates would still be complicated and inefficient, without being able to claim to be more than a very rough approximation of an arbitrary billing system.

Interestingly, less detailed information would be required from NEPOOL for rates based on NEPOOL system lambda than for rates based on utility hypothetical own-load dispatch. NEPOOL system lambda is a concrete, actual number which represents the running cost of the most expensive unit on the system at any point in time. This number is available to NEPOOL's dispatchers on a real-time basis, and is used for such purposes as determining when interchanges with other pools are economically justified. Thus, all that is necessary for determining NEPOOL-lambda-based rates is a readout of NEPOOL's computer tape record for this one parameter for the period in question. Accordingly, rates based the NEPOOL lambda would require less interaction with NEPOOL staff than would those based on NEPOOL billing, in addition to NEPOOL lambda's advantages in simplicity and efficiency.

Q: Do the remainder of your comments assume that NEPOOL-lambda-based energy rates will be adopted by the Commission?

A: No. I have assumed that the basic approach of the proposed regulations will continue to be pursued. While it would be regrettable if the DPU ignores the real advantage of NEPOOL-lambda-based rates, the own-load-based rate design envisioned by the proposed regulations can be improved and refined to better approximate the fundamental theory of avoided cost adopted in the proposed regulations.

Q: Please describe any problems you have found in the proposed mechanism for setting a standard energy rate (IIC1).

A: The proposed regulations appear to contain four errors, which would prevent the energy rate from equalling avoided cost, and would therefore be in violation of §292.304(b)(4) of the FERC regulations. These errors involve:

a. the sign and magnitude of the variations of the production costing runs from the base case, as described in IIC1a;

b. the fuel costs to be used in IIC1a, and their compatability with the fuel clause;

c. the line loss factor prescribed in IIC1c; and

d. the requirement that a particular time period be used as the basis for estimating the avoided cost of a NEPEX savings share in IIC1d.

Furthermore, there are two serious omissions in the discussion of energy rate calculations. First, no reconciliation mechanism is provided. Second, the regulations do not discuss the interaction between retail utilities and their wholesale suppliers. Both of these omissions may also result in a failure to approximate avoided cost.

Q: Please describe the errors in the specification of required production costing runs in IIC1.

A: The proposed regulations require, for utilities with retail sales over 500 GWH, that

"The utility will run a production cost model at 100%, 90%, and 80% of the expected load for each hour, with all other inputs held constant....The avoided fuel and O&M costs for each rating period will be the greater of: the difference in the cost per kwh (by rating period) between the 100% of expected load case and the 90% of expected load case; and the difference in the cost per kwh (by rating period) between the 100% of the expected load case and the 80% of expected load case."

This procedure will not measure the avoided costs due to the QF's on line. The cost avoided by the QF's is actually

(the cost of carrying the load without the QF's) -

(the cost of carrying the load with the QF's),

or the cost of area A in Figure 1. The regulations propose paying the QF's for displacing area B or C in Figure 1.

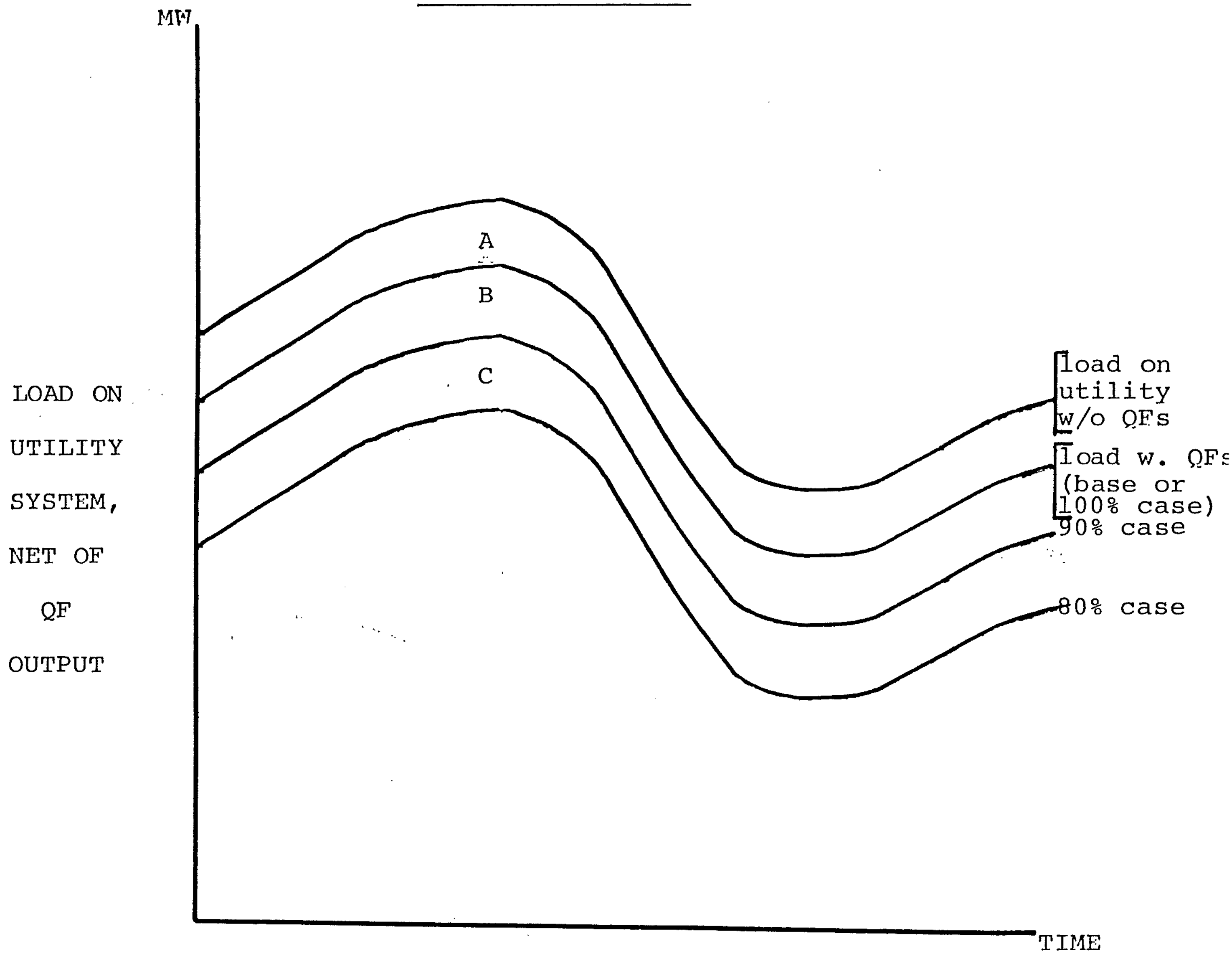
Since these areas represent lower load levels than does area A, they will generally have lower costs per kwh. Using the proposed calculation will therefore result in undervaluing energy supplied by the QF's.

In short, the proposed regulations would not pay the existing QF's for any of the actual costs they avoid, but only for the lower costs that would have been avoided by additional, as yet non-existent, QF's if they had been built. This is absurd, unrealistic, and inconsistent with the FERC regulations.

FIGURE 1

ILLUSTRATION OF AVOIDED COSTS AND

DECREMENTAL COSTS



A = AVOIDED COST DUE TO QFs

B = AVOIDED COST DUE TO 10% FURTHER REDUCTION

C = AVOIDED COST DUE TO REDUCTION FROM 90% TO 80% LOAD

Q: How should the production costing be performed?

A: Since the FERC regulations require that the DPU recognize

> The individual and aggregate value of energy and capacity from qualifying facilities on the electric utility's system (§292.304(e)),

it may be appropriate to credit the QF's as a whole with the aggregate value of the energy they displace, on the difference between

a. the expected cost of meeting expected load, and

b. the expected cost of meeting expected load, plus the load (including losses) reduction due to the QF's,

all divided by the number of Kwh displaced. If the amount of load displaced by QF's is small, the expected marginal cost (the cost of the marginal unit) can be used in lieu of the expected incremental cost. This information is directly available from some costing models. In no case should the energy rate be based on decremental costs, as currently proposed.

Q: You have explained why the load increment should be based on the amount of energy provided by QF's, rather than on some arbitrary percentage basis. If the DPU decides to use an arbitrary percentage increment, what considerations should be incorporated?

A: If an arbitrary fixed increment <u>is</u> used, the DPU should be careful to define a real increment, rather than the decrement defined in the proposed rules. The fixed percentage increment should also be large enough to cover possible QF development during the period of applicability of the regulations. This would require a very substantial increment: if the existing 17.9 MW of industrially-owned generation in Fitchburg's service territory is converted to operation as QF's, it would represent some 35% of FGE's 1979 average load of 51.5 MW, and an even higher percentage of FGE's expected load net of sales by the QF's. Setting a fixed percentage which is high enough to pay Fitchburg's existing generators properly may result in overpaying QF's in other service territories, at least in the short term. However, a 25% to 35% penetration (as a fraction of net utility load) does not appear to be unrealistic for most utilities within the next few years, since this figure includes existing sources as well as new ones, so any fixed percentage increment should probably be in this range. Increments equal to actual QF contribution still seem to be superior to any arbitrary percentage.

A: The aggregate - value method you have discussed would allocate to the QF's all of the energy savings due to existence of the QF's, with no savings for consumers. Is there an alternative?

A: Yes. The increment used to assess the value of each QF's production could be equal to the output of the individual QF, if the FERC regulations are not interpreted to require aggregate pricing. Thus, a 2 kw QF could receive marginal cost, while a 50 MW QF receives the value of a 50MW increment. In principiuple, a separate run might have to be performed for each QF, except the very small, marginal facilities.

Rate making could be simplified by establishing a single rate based on an increment equal to the output of the largest QF on the system at any time. The largest QF would then be paid for its individual contribution to reducing system costs, while the other QF's were paid more than their individual value. But the total paid out to all QF's would still be paid less than the aggregate value of all QF's on the system, leaving the remainder as savings for consumers.

It would not be appropriate to pay all QF's on the basis of marginal avoided cost. First, large QF's would be paid less than their value to the system. Second, a large potential QF, who could produce power more cheaply than the utility over the entire load increment it would displace, might be discouraged by the very much lower marginal cost its construction would produce. Paying only marginal cost to supra-marginal facilities would be unfair and would discourage some economical facilities.

Q: Please describe the errors in the proposed regulations regarding the fuel costs to be used in IIC1a, and the compatibility of those costs with the fuel clause.

A: The FERC regulations require the use of avoided costs; therefore, the relevant fuel cost is not the average price of fuel for each generator, as used in fuel adjustment calculations, but the price which would have been paid for the additional fuel which would have been burned in each generator, if not for the QF's. The proposed regulations incorrectly assume that average and avoided fuel costs are identical.

In general, the cost of the stock of fuel on hand at a generator will not be the same as the cost of replacing that fuel with additional purchases today, or this month, or next month. Because of the continuous variations in fuel prices, and the complexity of inventory and purchase policies, it may not usually be possible to predict the replacement cost precisely enough to improve significantly on an estimate based on the price of current purchases. Current purchase price will still generally be higher than the average price of fuel in stock; in times of rapidly escalating oil prices, it will be much higher. It is essential that the oil-burning QF's, which must buy oil at current prices, be compensated on the basis of current, rather than historical fuel prices. It is likely that true replacement fuel cost is, in fact, higher than current purchase prices (at least, as long as fuel prices continue to rise), but this is likely to remain an unquantifiable element of underestimation.

Certainly, no rate based on fuel prices below current levels can adequately encourage the proper amount of economically justified QF generation, or comply with the FERC regulations.

At some times, the discrepancy between average fuel price and marginal fuel price is particularly large and obvious. Some generators have access to limited quantities of low-cost fuel; for example, natural gas or NEES' oil from its NEEI subsidiary. Since all the cheap fuel available will be used eventually in any case, the cost avoided by running the marginal unit less is the cost of the market place oil that will not be burned later because more of the cheap fuel will be left for later use. The avoided cost for these units, when they are marginal (and when they are identifiable) should be adjusted upward from the level used in the fuel clause simulations before the production costing for QF purchase rates are performed. For example, if Brayton 4 is burning 20% NEEI oil at $15/bbl, 40% old marketplace at $25/bbl, and 40% new marketplace oil at $35/bbl, the fuel clause runs will use an average price of $27/bbl, while the QF rate runs should use $35/bbl, the price of the avoided fuel. Therefore, the statement in the proposed rules:

> The average cost of fuel per kwh in the base case (100% of expected load) must be the same as the charge(s) proposed for the fuel adjustment clause.

is factually incorrect. Total hourly output, plant availability, and heat rate assumptions should be identified between these runs, but individual plant output fuel prices will differ.

Q: Please describe the error in the prescription of the line loss factor in IIClc.

A: The proposed regulations require that the purchase rate include a correction for average line loss at the voltage level of delivery. The inclusion of line losses in the purchase rate is correct since a kwh delivered to customers (or along the line of power flow to customers) allows the marginal utility unit to be backed down by one KWH plus the losses which would have been incurred in transmitting, transforming, and distributing the power.

The proposed regulations err in their use of only average, rather than avoided losses. Losses due to resistance in utility equipment increase as the square of current, so the marginal (and hence avoidable) losses associated with the last kwh sent into the transmission/distribution system are approximately twice the average losses at that load level. Appendix 1 to this testimony proves that the appropriate loss multiplier for purchased power rates is

$$(1+L) / (1-L),$$

where L = losses - utility net generation. (This is also essentially the formula used by MECO in its response to DPU 18810. See Appendix A) A moment's inspection will confirm that this multiplier is greater than one plus twice the average loss ratio, L, which would be utilitzed under the proposed rules. For L=10%, the multiplier is 1.222; for L=15%, the multiplier is 1.353. In the latter example, which may well be typical of secondary distribution at peak periods, the proposed rule would compensate QF's at the rate of 1.15 marginal utility kwh per QF kwh, when the QF's are actually saving the utility 1.353 kwh for each kwh the QF generates. Thus, the QF would be paid a full 15% <u>less</u> than avoided cost under the proposed rules.

Not all QF's will deliver power directly to users or to appropriate points in the path of power flows to customers. Remote plants may inject power into already heavily loaded transmission facilities, increasing losses in at least part of the system. Very large plants with low surrounding load density may actually reverse flows on the local system and even requiring transformation to higher voltage levels. These situations do not seem to be typical, however. Most large plants will probably be cogenerators, whose power will be partly absorbed by the facility using the cogenerated heat, with the remainder used by neighboring facilities; the large industrial, commercial, or residential facilities capable of supporting cogeneration projects are unlikely to be found in very isolated areas. Similarly, many of the first hydroelectric sites to be developed will be those where hydro power was previously used by industry, and hence will be near load. Most of the current interest in wind-powered generators (in number of units, if not in annual MWH) appears to be in the form of small, backyard units, which will displace only the owner's load and perhaps that of a few neighbors.

Therefore, payment of less than the full marginal loss factor should be permitted only when the utility can demonstrate that the power delivered by a particular QF (or a set of similarly situated QF's) does not provide these savings. In these situations, the actual losses to be expected from the generator to the physical loads served should be subtracted from the loss factor credit; this may, in extreme cases, result in a negative credit due to losses.

Q: Why should the DPU not require the use of a particular time period in prospectively determining the size of a NEPOOL savings share and the fraction of that share to be added to or subtracted from the results of the production costing run?

A: The most recent three-month period is not necessarily the best available guide to the value of the NEPOOL savings share (share size) or to the fraction of time a particular utility is selling to the pool (selling fraction). Both of these factors are affected by load levels and by plant availability; the size of the savings share should also be roughly proportional to fuel prices. It may be possible to base projections of share size and selling fraction on historically observed seasonal patterns, and projected fuel costs, with adjustments for plant availability based on either historical patterns or explicit modelling, and therefore more closely approximate the DPU's concept of avoided cost.

The inter-period differences in savings share size and selling fraction may be substantial. Consider the case of Boston Edison, which has summer peaks about 200 mw higher than its winter peaks. Since NEPOOL's use pattern is the reverse (winter peaks exceed summer peaks by about 1500 MW), BECO should shift seasonally from larger purchases in the summer to larger sales in the winter. This tendency would be enhanced in those years in which Pilgrim I is refueled, or otherwise out of service, in the summer. At a hearing held in the fall to rates for the winter quarter, the most recent three-month period (given the delays in NEPOOL billing) might well be the summer months, when BECO was buying heavily at prices based on July fuel costs. Using this data to set project BECO's selling fraction in the winter months on the average size of the savings share at January prices would not be appropriate.

Q: What standard would you suggest for replacing the language in the second paragraph of IIC1d?

A: This section of the regulations should require the use of the best available estimate, based on relevant historical data and projections consistent with those used in the fuel clause projection and elsewhere in the QF rate projection.

Q: Why should there be a reconciliation mechanism in the QF ratesetting process?

A: Quite simply, the only way that the avoided cost (under any definition) can be known is retrospectively. Fuel prices, demand levels, plant availability, the size of NEPEX saving shares, and the fraction of time a utility is selling to the pool can be estimated in advance, but the actual values will only be available after the fact. Therefore, in order to pay avoided cost, the utilities must reconcile their prospective estimates with actual results.

The reconciliation mechanism would have other advantages as well. It would decrease the importance of precise forecasts of avoided costs, thereby simplifying and deferring the prospective portions of the ratesetting procedure, since any errors would be corrected over the next several months. It would give better price signals to QF's; if high demand, fuel price increases, or plant outages raise the utility's costs, the QF can respond by increasing output, draining storage (in the case of hydro and biomass facilities), decreasing internal consumption, or delaying scheduled maintenance, knowing that it will eventually be compensated at higher than the posted rate. The same process would work in reverse, encouraging QF's to back down their most expensive output, perform maintenance, and increase fuel storage when power is less valuable. Finally, reconciliation would decrease the extent to which the utilities, historically hostile towards competition from small power producers, could reduce the energy rate to QF's by manipulating projections and other data.

Q: It has been suggested that the utilities' desire to avoid underestimating their fuel adjustments would result in systematic over-estimates of the QF energy purchase rate. Is this true?

A: Not necessarily. Even with the best of intentions, utilities would be hard-pressed to predict the high-avoided-cost periods which result from sharp increases in oil prices, unusually extreme weather conditions, and simultaneous outages of several baseload plants. Certainly, the DPU (especially with an expanded fuel clause staff) should be reluctant to approve fuel adjustments based on projections of these worse-than-average conditions. While conditions will occasionally be better than predicted, the assymetries in the situation (e.g., fuel prices rarely fall dramatically; marginal costs rise rapidly as increasing load or outages push gas turbines into service, but costs fall slowly as decreasing load allows intermediate oil plants to be replaced by base load oil plants) virtually assure an overall tendency to underestimate.

Furthermore, if utilities want to understate avoided cost, it should not be very difficult to do so without greatly impacting the fuel clause. Understating the price of #2 oil, which will often be marginal, and overstating even slightly the price of higher sulfur #6 oil, which is rarely marginal and is used in much greater quantity than #2, might actually overestimate the fuel clause while underestimating avoided cost. Similar effects can be achieved by manipulating heat rates of various units, or by overstating the availability of intermediate-load units and understating the availability of base-load units. Over-estimating the fraction of time that the utility will be a net buyer from NEPOOL would decrease the rate to QF's without necessarily affecting the fuel clause. Creative utilities will find other ways to understate projected avoided cost while maintaining their fuel clause revenues.

Q: What aspects of the interaction between retail utilities and their wholesale suppliers have been neglected in the proposed rules?

A: The rules fail to recognize that there is a feedback mechanism from retail company energy consumption to wholesale company costs, and hence to the rates charged to the retail company. When a QF allows the retail company to reduce its wholesale energy purchases, the retail company saves an energy charge, based in part on the average cost of fuel to the wholesale company. (Montaup's energy rates consist solely of fuel costs, while NEPCO's energy charge includes some other expenses as well.) But the reduced load also lowers the average wholesale energy cost, since the QF backs off the most expensive unit on the wholesale company's system. For example, suppose that NEPCO's average fuel charge is 5¢/KWH and that the marginal NEPCO unit costs 10¢/KWH to run. Then a QF which reduces MECO's wholesale purchases by 2000/KWH (by producing somewhat less than that number of KWH and reducing losses accordingly) saves MECO $100 in fuel charges immediately. It also saves NEPCO $200, or $100 net of the reduction in revenues from MECO. This $100 savings lowers the fuel clause (either immediately or at the next reconciliation), and is returned to the customers in proportion to their energy use. Since MECO uses about 60% of NEPCO's output, about \$60 in savings flow back to MECO. Hence, the QF should be paid \$160, or 8¢/KWH, for providing the power to MECO, since that is the cost avoided by MECO. Stated more generally, the avoided fuel cost (A) to the retail utility is

$$A = a + f\ (m - a)$$

where a = average fuel charge of wholesale utility

m = marginal fuel cost of wholesale utility

f = fraction of wholesale utility's output sold to this retail utility.

Note that when <u>f</u> is unity, so that the retail company is the only customer of the wholesale company, the retail company's avoided cost is the same as the wholesale company's avoided cost. Note also that both <u>a</u> and <u>m</u> must be corrected for avoided losses.

For MECO and Eastern Edison, the <u>f</u> parameter is large and important to recognize. For Manchester, <u>f</u> will be very small. Actually, MECO customers may benefit almost as much from the operation of a QF in Manchester as would Manchester's customers, and MECO's customers should really pay such a QF for those benefits. (This issue will be raised again in my discussion of wheeling) Whether the <u>f</u> factor significantly impacts the value of reduced purchases under contract demand arrangements, such as Fitchburg's with BECO, depends on the amount of time that purchase is marginal, as well as the size of the contract relative to the seller's system.

<u>Section II - Reporting Requirements</u>

Q: Should any reporting requirements be added to section II Cle of the proposed regulations?

A: Yes. The data to be reported should also include actual historical values for the reconciliation, hourly breakdowns of avoided cost, the variable O&M values assumed for each generator, losses as a function of load at each voltage level, and a description of the computer model or other calculations from which expected avoided cost was projected. The need for this data is self-evident, except for the hourly breakdown. To the extent that avoided cost is calculated, prospectively or retrospectively, on an hourly basis, that disaggregation should be available so that

1. the appropriateness of the number, size, and timing of the standard rating periods can be determined, and

2. if QF wishes to negotiate for a contract based on different rating periods, such as those corresponding to hours of operation of the facility using cogenerated heat, or to thehighest-value hours in which a storage hydro facility can release its variable supply of water, the QF will have access to the necessary data on a regular basis.

<u>Section II - Capacity</u>

Q: Do the proposed rules establish proper capacity-related price incentives for QF's?

A: No. The proposed rules fail to recognize

1. the importance of reducing New England's dependence on oil,

2. the value of capacity in increasing reliability both in periods of capacity shortage and in periods of capacity adequacy,

3. the value of QF capacity in avoiding costs associated with <u>existing</u> generators.

Q: Please explain how the importance of reducing dependence on oil should be reflected in purchase rates for QF's.

A: The basic rationale for utility construction of new generating plants is that they reduce oil use, and will be justified on the basis of oil cost and availability, including costs and availability constraints imposed by the Federal government in attempting to decrease oil imports (that is, in recognition of a shadow premium on oil). This is the core of the utility position in D.P.U. 19494, Phase II, regarding Pilgrim 2, and in the various Seabrook purchase cases (e.g., D.P.U. 20055, D.P.U. 20248). This position is probably stated most succinctly in the letter of transmittal for the 1980 NEPOOL forecast to the EFSC in which James R. Smith, Secretary of the NEPOOL Planning Committee and Director of NEPLAN, said

> "Adequate reserves are indicated for the expected peak loads through 1991/92, assuming all five "NEPOOL Planned" units are in service as

scheduled, even though two units do not, as yet, have construction permits. Additional capacity will be required for 1992/93 and beyond.

"However, with approximately 60% of the existing capacity in oil-fired units, energy deficiencies could occur in the mid 1980's. It is especially critical that all non-oil fired capacity be built as scheduled and that conservation and load management efforts be continued to prevent energy deficiencies and to achieve the lowest possible price for electric energy."

Therefore, the most important capacity credit would be reflected by a shadow premium on oil, rather than in an explicit credit for contribution to reliability.

Q: Why is a shadow premium appropriate and necessary?

A: Utility planning and construction of generating facilities is premised on three factors which are not reflected in the current price of oil: expected future oil price increases, uncertainty in future oil prices, and uncertain oil supply continuity. None of these factors would be fully reflected in purchase rates for QF's based solely on current fuel costs.

Utilities may properly justify the construction of an oil-displacing generator, or conversion of an oil-fired plant, on the basis of fuel savings over the entire life of the plant. In DPU 19494, for example, some of BECO's projections indicated that Pilgrim II would not have positive net benefits until 2005, twenty years from the projected on-line date. If the plant is built, however, BECO will collect its capital and operating costs from the first year, effectively moving forward the incentives for BECO to displace oil. Under the proposed regulations, QF's would have to wait until the oil price actually rose before they would recover their costs. Accordingly, QF's whose owners cannot afford 20 years of deficits, may be deferred for years or may never be built, even if they can provide power as cheaply as utility sources.

It is also quite proper for a utility to recognize the uncertainty in future oil prices by accelerating its efforts to get off of oil. This is a logical consequence of the generally risk-averse preference of businesses and consumers: most people will pay a bit more, on average, to reduce the uncertainty of financial outcomes. The utility's own oil-reduction program is fraught with its own uncertainties (unknown final plant costs and reliability, for example), and these must be weighed against the uncertainties which flow from oil dependence. The QF owner faces similar uncertainties--how much will the plant cost to build and to run, how many KWH will it produce, what will the purchase rate be in 1990--but the utility and the consumer are shielded from these. The QF gets paid only what its power is worth, so any construction, operation, reliability, or fuel supply problems are solely the concern of the QF. If all the costs of risk are assumed by the QF, and all the benefits of risk reduction (mostly from decreased oil use) are assumed by the utility, the QF has been paid less than the avoided cost, and some economically advantageous projects will never be built.

Finally, utilities have a legitimate concern with oil supply continuity. New non-oil-fired plants, coal concersions, and increased storage capacity are allways of reducing utility sensitivity to oil production in adequacy, oil refinery capacity deficiency, and embargoes. Future government restrictions on oil use for macroeconomic and security purposes are also mitigated by new plants and conversions. Some utility expenses for this purpose may be avoidable if QF's reduce oil use, thereby increasing the effective storage capacity of existing facilities and reducing the vulnerability of the system to oil unavailability. The QF's will be of greatest benefit to the utility and its customers if and when oil supplies are actually cut off or cut down, resulting in emergency conversions, expensive out-of-region power purchases, and perhaps even the sort of painful, sacrificial emergency conservation experienced in the winter of 1973-74 and the current gas shortage. When such an event occurs, it will be far too late to encourage the development of QF's to meet it. Only some bonus for getting oil-displacing QF's on line <u>now</u> can hope to ameliorate or prevent such an emergency.

Q: Are there other benefits to reduced oil consumption?

A: Yes. The additional benefits include reduced regional oil imports; reduced upward pressure on world oil prices, including those paid by utilities; reduced macroeconomic effects (inflation, recession, balance of payments) resulting from oil import price and quantity; increased security of national and regional oil supply; and unquantifiable (but potentially substantial) improvements in the international political position and stability of the United States, of the industrialized West, and of the world in general.

Q: How can the value of these benefits be quantified for payment to QF's?

A: Most of these considerations are not unique to the utility industry, and are discussed elsewhere, particularly in Energy Future and by DOE in its Advanced Notice of Proposed Rulemaking in the Federal Register for October 7, 1980. DOE notes that three studies have estimated values of the import premium associated with direct price effects, macroeconomic effects and (in one case) security effects ranging from $13-72 per barrel of oil. DOE revises some of the Energy Future assumptions and derives a range of $7-23, and suggests a range of $3-10/bbl for project evaluation. None of the studies includes all of the impacts listed above; specifically, all of them neglect the impact on utility construction planning.

Therefore, it seems appropriate to recognize the value of reduced oil use by paying a premium for any QF power which displaces oil. The values reported by DOE for various studies amount to shadow premia of about 20%-150% over market price; none of these are complete. DOE's own proposed import premia for federal energy planning are about 10-30% of market price. In the section of the Energy Security Act dealing with municipal waste-to-energy facilities, Congress has set price supports at 125% of the cost of #6 oil; this is equivalent to a 25% shadow premium (PL 96-294, §234 (d)(4)(B)). The analysis in the testimony of Chernick and Geller for DPU 19845 suggests that a shadow premium on current oil prices on the order of 38% would have been necessary to justify building Pilgrim 2, even assuming that peak capacity was needed and that construction started in 1980. Overall, applying a 20% shadow premium on oil seems to, if anything, understate the value of reducing oil use and provide less of an incentive to QF's than utilities apply to their own projects.

The shadow price should be applied in all hours in which oil is the marginal fuel in NEPOOL. QF's which use no oil or gas should receive the full credit; those which burn oil and gas should receive less than the full credit in proportion to the ratio of their effective heat rate to the marginal system heat rate. For simplicity, this ratio, which will be about 0.5 for most cogenerators, might best be calculated on an average annual basis.

Q: How do the proposed rules fail to recognize the value of increased reliability?

A: The proposed rules envision that, for generating utilities (as opposed to such distribution companies as MECO, EECO, and Manchester) capacity credits will only be given for capacity which is made available for part or all of the planned life of one of a certain set of units which are planned but not authorized in some period after the QF is on-line. As I will explain below, this scheme is administratively unworkable, does not describe avoided costs in any useful fashion, and is equivalent to a decision not to pay capacity credits. This approach also ignores the value of capacity in times of shortage for which no utility-owned capacity is planned and in times of adequacy.

The first case is obvious. If the utility is facing a capacity crunch, and has no pending plans to avoid that crunch, the QF is especially valuable. Since the proposed rules only grant capacity credit for periods in which utility units are planned, there is no mechanism to encourage the construction of QF's to meet shortfalls.

The second case is a bit more subtle. While NEPOOL and most of its Massachusetts members have capacity surplus and are likely to maintain this surplus throughout the next decade, additional capacity continues to have some reliability value. One such value is that additional capacity, which operates at any time at which a shortage in capacity might occur, reduces the probability and expected severity of voltage reductions, customer disconnections, and related outage costs to both the customers and the utilitu. Widespread subregional customer disconnections and voltage reductions due to bulk power supply problems have continued to occur despite large reserves in New England, as the loss of a few large generators and transmission lines have forced the shedding of load in, for example, the Southeast Massachusetts area. The costs of these outages can be considerable, and although they are very hard to quantify (see testimony of DW Goins on behalf of BECO in DPU-19494, Exh. BE-II-1800), there is certainly some cost to any customer, and hence an avoided cost due to added reliability. This avoided cost can only be determined on an overall, estimated basis, since it will rarely be possible to know whether, but for the QF's, utility resources would have overloaded and failed, forcing voltage reductions and blackouts.

Additional capacity will also facilitate the economic scheduling of planned maintenance, allow malfunctioning units to be repaired promptly, and allow nuclear units to be refueled at the most advantageous point in fuel life, rather than as required by reliability considerations. This additional flexibility should lower fuel costs and maintenance costs by relaxing the reliability constraint on utility operation.

Q: How does increased reliability from QF's allow the utility to avoid costs associated with existing generators?

A: Additional capacity, by increasing the reliability of bulk power supply, may reduce utility costs by allowing for the derating of some units' readiness (from operating reserve to hours' notice to days' notice), the mothballing of some units (i.e., placement in deactivated reserve), the earlier retirement of some units (as Edgar was retired) and/or the sale of peaking units (diesels or turbines) to utilities in other regions, or to potential cogenerators. It may also allow the utility to reduce its fixed costs by selling off entitlements in its plants to other utilities, these unit sales are commonly practiced in New England on both the short term (as short as a few months) and the long term (as long as the life of the unit).

Q: What are the other problems with the capacity credit calculation as contemplated in the proposed regulations?

A:

1. Apparently, only existing QF's could sign a contract for capacity purchase and only in the interim between announcement and approval of the utility's plant. Thus, a QF would have to be built without the developer having any idea what capacity credit it might eventually earn, if any. Furthermore, given the ten to fifteen year construction time for large utility plants, the QF may well spend half its life waiting for a credit, even though it may be allowing for the delay or cancellation of other plants in the interim.

2. The rate would be based on the cost of a unit actually built, not on the cost of the unit whose construction was avoided. Hence payment is based on "not-avoided" costs.

3. Estimates of the plant's fuel cost, system incremental fuel costs, O & M expense, capital additions costs and capacity factors for the life of the plant (30 years or perhaps more) will apparently be required to determine the proposed capacity credit.

4. The proposed regulations do not address effective load carrying capability, or any alternate measure of real contribution to reliability.

5. The proposed regulations provide no guidance concerning the nature of the contract required for capacity credits.

6. The regulations do not adequately define such concepts as "planned" or "officially approved", whether QF's must be on-line before they have the right to sign a contract to provide capacity, whether actual or projected utility costs will be used, whether net capacity cost will be determined on an annual basis or for the life of the plant, and how payments will be made in the event of deferral or cancellation of utility plants.

In essence, the provisions of sections IIB and IIC2 amount to a refusal to grant capacity credits to QF's supplying power to generating utilities. This situation clearly does not reflect the potential for QF's to allow utilities to avoid incurring costs.

Q: How should the proposed regulations be amended to allow for more representative estimates of avoided reliability-related capacity costs?

A: The regulations should establish a mechanism for annual assessments of the value of capacity, measured in dollars per KW of effective load carrying capability. For utilities which buy, rather than generate, their power, the method in the proposed regulations appears appropriate. For both buying and generating companies, capacity credits should be paid in all years and for all facilities which improve reliability (for generating utilities) or reduce peak demand (for buying utilities).

Q: Why should effective load carrying capability be the basis for capacity credits from generating utilities?

A: ELCC or a similar probabilistic measure is necessary to accurately allocate the value of various types and sizes of generators. The measure should recognize that small (say, up to 5 MW), randomly available, independent generators are, in the aggregate, a firm source of power of high reliability, regardless of the performance of individual units. Therefore, these small units can be given a capacity credit on the basis of their KWH output (actual or prorated) in the peak period of outage exposure, and require no direct measurement or special testing for the purpose of reliability credits. Power producers which are significantly correlated with demand (_e.g._, cogeneration equipment on heating systems) or with other producers (_e.g._, solar, wind) should receive the same credit as other small producers until the utilities can determine from stochastic computer modelling what the exact credit should be. The complex and vague concepts of reliability assessment sometimes advocated by the utilities (_e.g._, "dispatchability", contracts, guarantees, all-or-nothing credits, availability standards, failure to recognize the direct effects of unit size) should not be allowed to interfere with incentives for QF's to improve system reliability and displace oil.

Section II - Special Situations

Q: Are there any special situations in which avoided costs vary between portions of a service territory?

A: Yes. There are "islands" of electric load which are poorly connected to the grid as a whole and in which a QF is more valuable than it would be elsewhere. There are four reasons for this additional value:

1. Losses involved in serving the island will tend to be high when the tielines are heavily loaded. The QF should receive credit for reducing those losses.

2. When the tie lines are very heavily loaded, generators within the island must be run to meet incremental load, even though there are cheaper power sources elsewhere on the system. The QF should be credited with the cost of the higher-cost local power which would be required if the QF were not operating on the on the island.

3. When the tie lines are somewhat less heavily loaded, it may still be necessary to maintain local generation operating reserve to prevent blackouts if the tie lines fail. Especially in the case of steam turbines,this reserve can be expensive, and to the extent that the QF can reduce the cost of keeping units on standby, the QF should be so credited.

4. Additional capacity is planned for some islands, and otherwise uneconomical capacity is retained in some other islands to prevent local capacity shortfalls. Thus, even in a general excess-capacity situation, strategically placed QF's may allow deferral, cancellation, or retirement of these local generators.

Some "islands" are physical entities such as Martha's Vineyard for which NEGEA plans the addition of a 2.75 MW diesel (to its current 14 MW) every few years, and Gloucester where NEPCO maintains 28 MW of diesels. Other islands are solely electrical in nature. BECO has explained the must-run status of New Boston as an area-protection mechanism, to avoid leaving the metropolitan area "hanging on tie lines". CELCO justified the continued presence in rate base of the Blackstone station, despite its exorbitant cost per Kwh (17 ¢/Kwh in

1978) on the grounds that it was necessary backup in case ties to BECO failed, and that the alternative to Blackstone was a new, expensive interconnection with the grid.

The utilities should be required to identify each island in their systems, the hours in which local generation is run (or kept in operating reserve) at added cost to protect service to the island, any quantifiable additional losses involved in serving the island as opposed to other portions of the service territory, the facilities maintained or planned to continue reliable service to the island, and the costs of those facilities. QF's which, by their fortuitous placement, allow for the deferral of capacity additions (e.g., new transmission ties, the Vineyard diesels), the retirement of otherwise uneconomical facilities (e.g., Blackstone), a reduction in the operation of relatively inefficient generation, or increase the reliability of service, should be paid for the costs avoided by the utility and its customers.

Section II - Wheeling

Q: What comments would you like to make regarding the discussion of wheeling in section IID of the proposed regulations?

A: In New England no wheeling charge for power generated by a QF is ever justified. The FERC regulations (§292.303(d)) limits wheeling charges to line losses. Due to the operation of NEPOOL, the dispatch of generators and the use of transmission lines will not be affected by the "wheeling" of power. In fact, the transaction will take place solely on paper, as do all transfers of entitlements of power from utility-owned plants within NEPOOL. Therefore, unless some arrangement is made for out-of-region transmission of power which actual charges the losses incurred, no wheeling changes of any sort are permissible.

Q: Do you have any other suggestions regarding wheeling?

A: Yes. If the DPU does not use NEPOOL avoided energy costs, the Commission should instruct all utilities to exercise their option to wheel QF power to any other utility to which the QF wishes the power wheeled. This will ensure that any QF, whose construction is economically justified by the avoided costs of <u>any</u> utility, will be constructed. Otherwise, relatively cheap capacity opportunities which happen to be located in the service territory of a utility with low avoided costs (as calculated under the avoided-cost concept of the proposed regulations), may not be developed. Using the company-specific cost calculation and forcing QF's to sell only to the local utility can hardly be said to "encourage small power production and cogeneration", as required by PURPA.

Section III

Q: What improvements might be made in Section III of the proposed regulations?

A: This section should be modified to require standardization of as many charges as possible. The utilities should propose, and the DPU should review, revise, and approve:

1. standard fees for the initial safety inspection, perhaps varying with generator type, size, and location (e.g., at the top of a 200-foot tower, under 20 feet of water), but limited to reasonable average labor requirements;

2. standard charges for metering, by voltage level, phasing, and KW ratings, along with rates for meter purchase and maintenance for QF's who choose to own their meters; and

3. standard charges for any common interconnection services and equipment, such as actually attaching the QF's lines to the company's lines, costs of lines (per foot), transformers, and the like, and the cost of capital to be used in assessing carrying changes.

In addition, no charge for any kind of reliability testing should be allowed except for facilities which are claiming a capacity credit from a generating utility, a nearby impossible task under the proposed regulations. Obviously, reliability is not an issue for QF's not claiming capacity credits. For QF's selling power to distribution companies (MECO, Manchester, EECO), only the actual (or estimated, prorated) output at the time of peak demand is relevant, so reliability is not important. Those QF's who produce many KWH at peak will receive large payments, and those that do not produce many KWH will receive small payments.

Some provision should also be made for initiating the interconnection process. I would suggest that the utility be required to prepare a generalized questionaire for potential QF's, to allow for a prompt assessment of the costs and problems in inspection interconnection, and metering. Such questionnaire (perhaps with some modificatons in response to the date in the notice of intent) should be sent to each potential QF on request, or within 7 days of receipt of the notice of intent ot interconnect. It should request sufficient information to allow the utility to respond (within the 30 day period allowed by the proposed regulations) with reasonably reliable estimates of the various costs (exact prices for standard items) and requests for any special information which may be necessary.

Q: Does this conclude your testimony?

A: Yes.

#16 Comments

COMMONWEALTH OF MASSACHUSETTS

DEPARTMENT OF PUBLIC UTILITIES

REGULATIONS PROPOSED BY THE DEPARTMENT OF PUBLIC UTILITIES, TO ESTABLISH RULES BY WHICH A RATE OR RATES MAY BE CALCULATED FOR SALE OF ELECTRIC ENERGY BY SMALL POWER PRODUCERS OR COGENERATORS TO ELECTRIC UTILITY COMPANIES UNDER THE DEPARTMENT'S RATEMAKING JURISDICTION; AND OTHER RULES DETERMINED NECESSARY TO CARRY OUT THE PURPOSES OF THE PUBLIC UTILITY REGULATORY POLICIES ACT OF 1978 ("PURPA"), TITLE II, SECTIONS 201 and 210.	D.P.U. 535

COMMENTS OF THE ATTORNEY GENERAL

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TABLE OF CONTENTS

I. <u>INTRODUCTION</u>

The Attorney General's comments consist primarily of a redrafting of the Department's proposed regulations implementing PURPA §210. A few preliminary observations will precede an explanation of portions of the redrafted rules.

First, it is significant to note that the Attorney General's proposed rules do not assume the use of NEPOOL-based avoided energy charges. This is not due to any change in the Attorney General's position regarding the economic, practical, regulatory, and legal superiority of NEPOOL-based rates. Rather, the proposed rules have been drafted to assist the Department in implementing the much more complex company-specific rates in a reasonable fashion, if the Department continues to pursue that approach. However, considerations of wheeling, wholesale/retail interaction, reconciliation, and production costing simulations would largely be eliminated by NEPOOL-based energy rates, greatly simplifying the regulations.

It is the expressed position of Western Massachusetts Electric and of at least one Department staff member that the FERC regulations define "utility" in a manner which precludes the use of NEPOOL costs. This does not appear to be correct; to the contrary, as noted in Mr. Chernick's testimony, the FERC discussion of the "utility" often sounds more like NEPOOL than like a retail company. Even assuming, <u>arguendo</u>, that NEPOOL costs are somehow precluded from direct Department concern, the

NEPOOL system lambda is still a very simple, convenient proxy for the retail company operating cost. Since approximation will always be necessary, there is no reason not to utilize NEPOOL lambda, which eliminates so many regulatory complications, provides more stable incentives for QF's and fully protects consumers.

Second, the Attorney General is not recommending that the utilities be ordered to sign contracts, without addressing the issue of whether the Department has this power. The Attorney General recognizes that the utilities will have enormous bargaining power in negotiations with potential QF's, who may require contracts, access to capital markets, levelized rates, and other services or terms from the utilities. However, if the QF's have the rights to full and fair avoided-cost-based rates, and to wheeling (or to NEPOOL-based rates), they will also have considerable bargaining power, and will be able to trade future revenues for contracts, or whatever else they require. A utility which refused to negotiate in good faith would face the risk that the QF would come on line under the standard rates, and be entitled to full avoided cost.

In order to balance the bargaining power of the parties, the Department should make every effort to recognize the full avoided cost due to any QF, resolving all uncertainties in favor of the QF, and extending standard rates to all facilities. To do less would not encourage QF construction and would ultimately increase costs to the consumer. The Attorney General's proposed regulations would provide for paying the QF's the full cost that they allow the utilities to avoid.

Third, the Attorney General is concerned that the utilities would not be permitted to require expensive additional metering and safety equipment until it has been shown to be necessary and cost-effective. One example of this is BECO's proposal to requre KVa and KVaR metering. This requirement would be particularly suspect as kw metering inherently reflects the effect of power factor on delivered power.

II. COMMENTS ON THE ATTORNEY GENERAL'S PROPOSED RULES

Most of the changes incorporated in the Attorney General's version of the proposed rules are either self explanatory or are fully discussed in Mr. Chernick's testimony in this docket. The following sections may require some elaboration.

A. Section I.J. Purchase and Sale Options

Both simultaneous purchase and sale, and net purchase and sale (sometimes called "parallel operation", which also refers to an electrical arrangement, rather than a billing method) are clearly allowed by the FERC regulations, and neither seems to be opposed by any party. Several parties have advocated "reverse metering" or "net billing", in which a single meter serving both the QF and an associated load (generally a residence) would run both forward and backward, depending on whether the QF's output exceeds the associated load. If the avoided cost is determined to be close to retail rates, this practice may be justified for certain very small QF's. In the meantime, the Attorney General believes that the option in Section I.J.3. of the attached proposed rules would allow these small producers to interconnect without financial penalty, sacrificing minimal revenue to avoid metering and interconnection charges.

B. Section II.B. Avoided Energy Cost

This section is expanded primarily to:

1. differentiate between generating utilities and retail-only utilities, and describe appropriate procedures for each;
2. allow for reconciliation;
3. explain the intent of the Department to use best estimates of avoided cost, whether or not appropriate estimation methodologies have been identified at this time;
4. specify incremental, rather than decremental, production cost simulation, and set a fixed increment, rather than a percentage increment;
5. clarify the NEPEX adjustment for the benefit of those parties who have not previously understood this concept; and
6. clarify the calculation of avoided line losses.

C. Section III.D. Capacity Rates

This section sets up broad criteria for the types of avoided costs which may be included in the capacity credit. It also establishes the initial values of capacity credits, a mechanism for refining these values, and the procedure for allocating the credit to Kwh production by time period. Two points are particularly significant: the value of the initial capacity credit for generating utilities and the nature of the capacity credit for retail utilities.

The record in this case clearly establishes the validity of a current capacity credit to reflect current and near term avoidable costs. Mr. Terry C. Ranger of Western Massachusetts Electric Company has testified that peaking generation capacity, exclusive of related transmission and reserve requirement costs, currently has a market value of \$13/kw-year. Adding in the costs of transmission, substation, and distribution equipment, which utilities are still generally expanding, as well as the value of accelerated retirements, of reduced outage probability and of improved maintenance scheduling, the NEPOOL deficiency charge of \$22/kw-year seems, if anything, to understate the total value of capacity. Additionally, the fact that the NEPOOL participants have been able to agree on the \$22/kw-year value for use in their fraternal dealings legitimizes the use of the same value in dealing with QF's. In any case, the value is so small that it is hardly worth quibbling over, although it may be helpful to QF's in maintaining adequate cash flow in their early years.

The utilities' position that capacity credits cannot be given until some indefinite date in the future, when some particular actions can be attributed to the QF's, is both impractical and unwise. Existing QF's have already reduced the need for generation, transmission, and distribution facilities. If efforts to encourage QF generation (including the immediate payment of capacity credits) are successful, many new facilities may never be planned, let alone built. It may not be any easier to identify the specific capacity-related effects of QF production in 1990 than it is now. A forward-looking approach to capacity credits will help bring QF capacity on line, when and where they are most needed.

With regard to rates paid by distribution utilities, which do not own generating capacity, Massachusetts Electric has proposed a curious double standard. For energy charges, MECO wishes to use only its rates from NEPCO, without reflecting the flow of benefits back to MECO in the form of reduced fuel charges. For demand charges, MECO wishes to use NEPCO's own avoided costs, ignoring the wholesale rates completely. MECO further relies on the incorrect assertion that capacity has no value at all to NEPCO. This assertion is refuted both by Mr. Chernick's testimony and by Mr. Ranger's testimony, and it will not be discussed further here.

MECO's position is self-contradictory. By using wholesale rates for some purposes and the wholesaler's costs for other purposes, MECO is contriving to offer the lowest possible rates for QF power. Far from encouraging small producers, as required by PURPA and promised by NEESPLAN, MECO is clearly attempting to eliminate them. Mr. Newsham's protestations not withstanding, NEES has generally offered very poor rates to QF's, as evidence by "Interim Policy No. 10" in whch MECO refused to pay more than the fuel clause price, offered no capacity credit, and limited the offer to only certain energy sources under 10 KVa. It is unrealistic to expect this company to offer fair rates unless it is required to do so.

The avoided cost for MECO, based on the company-by-company approach which the Department has favored to date, would seem to be simply MECO's wholesale charge from NEPCO, adjusted for the portion of NEPCO's net costs which flow back to MECO. Clearly, NEPCO's fuel savings flow back to its customers. It is not so clear that NEPCO can not avoid costs comparable to its current demand charge to MECO, for example, by delaying some of the dozen transmission lines and two bulk substations listed as planned (most by 1985) in NEES' 1980 filing with the Energy Facilities Siting Council, or by increasing its off-system sales. Therefore, the burden should be on NEES to demonstrate that MECO's share of the NEPCO demand charge will in fact return to haunt MECO in the form of higher rates in the future. Even if this does occur, the capacity credit should reflect the timing difference in the flow-through.

In defending his interpretation of avoided cost, Mr. Newsham relies on three legal fictions. The first is that "the utility" whose avoided costs are to be the basis for QF rates must be MECO, without reference to NEPCO. As discussed above with reference to use of NEPOOL lambda, "the utility" to be used for costing purposes is never defined by FERC or by PURPA, so the choice between MECO, NEPCO, or NEPOOL-based rates is left to the Department. Certainly, the Congressional intent to "encourage cogeneration and small power production" can not be satisfied by using only MECO-based average fuel costs, while ignoring the real avoided energy costs and all capacity costs.

Mr. Newsham (on p. 9 of his testimony) goes so far as to insist that the Department can not legally examine NEPCO cost data to determine the reasonableness of MECO's cost projections, or the impact of QF's on NEPCO's fuel charge to MECO.

Mr. Newsham's second fiction is that wholesale demand charges can not be included as avoided costs. Nothing in the FERC regulations or in PURPA supports his position. Mr. Newsham does quote a section of the FERC commentary on the regulations, which clearly states that "the avoided cost would include the demand charge included in the wholesale rate" and then discusses the possiblity that some of the avoided cost might be offset by later wholesale rate increases, but does not create the presumption that this situation will occur. Mr. Newsham's entire argument hangs on the second-to-last sentence he quotes:

> As a result, rather than allocating its loss in revenue among all of its customers, in this situation the supplying utility should assign all of these losses to the all-requirements utility.

This sentence is contrary to PURPA, to the actual FERC regulations, to the entire preceding discussion in the commentary, and to FERC practice and precedent (which does not allow wholesale suppliers to discriminate against customers who conserve or otherwise reduce their demand). It should therefore be given little weight.

Mr. Newsham's third fiction is the most basic. He suggests repeatedly that the Department has only those powers regarding QF rates which are expressly granted by FERC. The Attorney General believes that the breadth of the Department's authority would have allowed it to promulgate essentially the same regulations, regardless of whether PURPA had ever been enacted, and is therefore not dependent on the authority conferred by Congress or FERC.

Hence, the scheme presented in the Attorney General's proposed regulations offers a more appropriate framework for setting capacity charges than that offered by the utilities.

III. PROPOSED RULES IMPLEMENTING SECTIONS 201 AND 210 OF THE PUBLIC UTILITY REGULATORY POLICIES ACT OF 1978 AND OTHERWISE PURSUANT TO THE DEPARTMENT'S AUTHORITY

I. Applicability of Rates and Terms Set Pursuant to Sections 201 and 210 of PURPA

A. All facilities which meet the qualifications promulgated by FERC in Rule 69 to become new qualifying cogenerators or small power producers are eligible for the rates set by the Department. A facility which intends to sell power to and/or interconnect with a utility must notify the utility of that intention at least ninety (90) days before the planned date of interconnection or sale. The Notice of Intent (NOI) shall include

1. the name and address of the applicant (the owner, operator, or other party responsible for financial and other dealings with the utility);

2. the location of the facility;

3. a brief description of the facility including:

    a. a statement that the facility is a small power producer or a statement that it is a cogenerator,

    b. the primary energy source,

    c. the extent of planned usage of fossil fuels,

    d. the anticipated maximum output capacity of the facility

    e. the nature of the generator (e.g., synchronous, photovoltaic, fuel cell), and

    f. the nature of any power conditioning equipment to be located between the generator and the utility's system;

4. the anticipated on-line date and beginning of installation of the facility;

5. whether it is anticipated the facility will operate as a net seller or on simultaneous purchase and sale;

6. the percentage of ownership by any electric utility, public utility holding company, or any person owned by either;

7. if the facility is a small power producer, the location in relation to any other small power producers with the same ownership located within one mile of the facility; and

8. if the facility is a cogenerator, whether it is a topping or bottoming cycle, and information demonstrating that the applicable requirements of §292.205(a) and (b) of the FERC regulations will be met.

B. Within ten (10) business days of receipt of an NOI, the utility may with good cause, notify the facility that it disputes the facility's status as a Qualifying Facility (QF), or that it lacks information neccessary for determination of QF status. Such notification shall include a precise statement of the grounds for dispute or of the nature of the incomplete information. The facility may at any time resolve the issue of qualification by seeking FERC (or in the case of facilities described in paragraph D hereunder, D.P.U.) certification. If the facility chooses to provide additional information to the utility, the ten day limit for utility response applies until the utility either formally disputes or accepts the qualifying status of the facility. Failure to respond within 10 days to any submittal in writing of an NOI or of supplementary information from a facility whose QF status has not been disputed shall constitute acceptance of such status by the utility. Any utility which accepts a facility's qualifying status may not subsequently dispute the facility's status unless the nature of the facility changes materially or the NOI or supplementary information is found to be materially incorrect. Any facility which has an application for certification pending before the FERC or the DPU will be treated in all respects as a QF by the utility.

C. All existing facilities which meet the qualifications promulgated by FERC for qualifying as a cogenerator or small power producer, and hence are QF's but which commenced construction before November 9, 1978, and hence are not "new capacity" under §292.304(b)(1) shall be eligible for the rates set pursuant to these rules for

1. production in excess of 1977-1979 average levels,

2. production from additional equipment within the facility, added after November 9, 1978,

3. production from existing facilities of less than 100 kw, and

4. production which the facility can demonstrate to the D.P.U. would not occur under the existing arrangements.

The utility shall offer to renegotiate or amend any contracts which would prevent such production from receiving such rates. Energy and capacity not from new capacity and not covered by any of the four preceeding criteria shall be purchased under existing arrangements, unless otherwise agreed by the parties.

D. Any facility which would meet the FERC criteria for qualification as a small power producer, except for the criterion regarding use of fossil fuels, will be eligible for all benefits for which it would have been eligible had it met that FERC criterion. Certification of such facilities, when necessary will be performed by the D.P.U., following the FERC procedures (§292, 207 (b)).

E. The following utilities are subject to these regulations:

1. Boston Edison Company (BECO),

2. Cambridge Electric Light Company (CELCO),

3. Eastern Edison Company (EECO),

4. Fitchburg Gas and Electric Company (FGE),

5. Manchester Electric Company,

6. Massachusetts Electric Company (MECO),

7. Nantucket Electric Company,

8. New Bedford Edison Light Company (NBE),

9. New England Power Company (NEPCO), and

10. Western Massachusetts Electric Company (WMECO)

F. A utility shall purchase power from any QF which wishes to sell such power to the utility and

a. is located in the utility's retail service territory,

b. is willing to provide or pay for an interconnection with an appropriate facility of the utility (e.g., a transmission line, distribution line, or substation), or

c. provides power to the transmission or distribution system of any wholesale customer (excluding unit sales) of the utility.

G. QF's and utilities may enter into any special arrangements regarding rates and terms which are consistent with the objectives set forth in PURPA §210 (a)(b), and (c). A utility shall respond substantively within 30 days to any inquiry or offer by a QF or potential QF, unless the QF agrees to waive this requirement.

H. Section II of these regulations establishes the basis for the setting of standard purchase rates for QF power, which are applicable to all such purchases unless

1. the purchase is from QF capacity installed prior to November 8, 1978, and not made eligible by section C supra,

2. a special arrangement is made between the parties, as provided in secton G, supra, or

3. the utility or the QF petitions the D.P.U. to set some non-standard rate for the QF.

Petitions for non-standard rates shall include an explanation as to why such a rate is appropriate. Non-standard rates may be requested by any QF. Utilities may request such rates only for QF's which are larger than 1MW, and only prior to interconnection or the expiration the notice period, whichever occurs later.

The D.P.U., upon examination of the materials submitted with the petition and of any response filed by the other party, shall determine whether the petitioner has established a prima facia case that a non-standard rate is necessary to encourage QF power production in the most beneficial fashion, or to protect consumers from excessively high rates. If such a case is established, the appropriate rate shall be determined at an adjudicatory hearing, after public notice.

J. Qualifying facilities may choose to interconnect under any of the following arrangements.

1. Simultaneous purchase and sale. All power produced by the QF generator will be purchased by the utility, and all station maintenance power and power for any interconnected facilities owned by the owner of the QF will be provided by the utility. Internal electrical usage by the QF, required for normal station operation, will be taken from QF output before metering, where feasible.

2. Net purchase and sale. Power generated by the QF will be utilized in the QF and connected facilities of the QF owner. If QF output exceeds QF (and connected facility) load, the excess will be purchased by the utility. IF QF (and connected facility) load exceed QF output, the utility will sell to the QF.

3. Interconnection without purchase. This option is essentially identical to net purchase and sale, except that power produced in excess of the QF owner's needs and provided to the utility, will not be metered or purchased by the utility. In exchange for this unmetered power, the utility shall provide all interconnection services, including inspections and ratcheting of the existing meter, at no cost to the QF. If existing service lines are not adequate to carry the QF power to the utility's distribution lines, the QF shall provide such lines to within ten feet of the utility's lines, or pay the usual charge for upgrading existing services. This option is primarily intended for use by small residential wind turbine installations, but is available to any QF willing to forego compensation for excess output.

A qualifying facility may elect any of the three options initally, and may change from one option to another by giving the utility ninety days notice and paying any costs required for additional or altered metering. A qualifying facility changing from option 3 to either other option shall pay any deferred interconnection charges.

II. Rates and Terms for the Purchase of Electricity from Qualifying Facilities

All standard rates will be based on avoided costs, and all terms will be determined on a non-discriminatory basis between facilities with similar supply characteristics. After promulgation of final rules, a special rate setting hearing shall be held for each utility to determine initial rates and terms for the purchase of electricity from qualifying facilities. After such initial hearing rates will be set pursuant to the rules which follow.

A. Energy Rates

1. The energy purchase rates shall be determined at least as often as and at the same time as the fuel adjustment charge for a utility and in no case less than annually. Rates for NEPCO will be set at the same time that those for MECO are determined.

2. The energy purchase rates set by the Department are standard rates available to all qualifying facilities (except as described in part IH above).

   a. Facilities which supply more than 40 KW to the utility shall have their energy purchased on a time-of-supply basis.

   b. Facilities which supply 40 KW or less to the utility on simultaneous purchase and sale shall have discretion to have their energy purchased on time-of-supply or flat rate basis, unless the utility chooses to pay for time-of-supply metering.

   c. Facilities which supply 40KW or less to the utility on a net purchase basis shall have discretion to have their energy purchased on a time-of-supply basis; purchased entirely as offpeak energy; or, if the facility can demonstrate that its load is essentially equal in the various rating periods, purchased on the standard flat rate.

B. Calculation of an avoided energy cost

1. Energy rates for generating utilities shall equal the avoided fuel cost plus the avoided operations and maintenance (O&M) costs plus the NEPEX adjustment, the sum of which will be multiplied by the quantity 1 plus the line loss factor (appropriate for the voltage level) as a decimal. Time-of-supply rates will be calculated for each of at least two rating periods (e.g., peak and off-peak). A flat rate which is a weighted average of the time-of-supply rates, where the weightings are the number of hours in each rating period, shall also be calculated. Each cost component utilized in calculating the energy rate shall be the best available estimate. Rates may vary with time, location, voltage level and any other identifiable factors which affect the avoided cost, and shall include all components of avoided costs which can be identified and quanified.

2. Avoided energy costs will be determined prospectively during a utility's fuel adjustment clause hearing. The input data and assumptions used to calculate avoided costs will be consistent with those used to calculate the fuel adjustment charge. At the time when a new purchase rate is authorized, the previous purchase rate will be reconciled with avoided costs in the previous period. Actual avoided costs will be calculated based on actual load, fuel prices, unit availability, NEPEX saving share size, status of the utility as buyer or seller in NEPEX, and all other available actual relevant data. The difference between actual costs and rates paid shall be reconciled through a proportional adjustment to all purchase rates in the subsequent period. Such adjustment may be differentiated by time of supply.

3. Calculation of generation-level avoided fuel and O&M cost

   a. Whenever feasible, avoided costs will include

      (1) the replacement cost of fuel, the use of which was avoided by QF generation;

      (2) all auxiliary costs associated with avoided fuel, including handling, storage, and transportation costs; and

      (3) a security surcharge on oil and gas use of

         (a) 20% of the market price of the oil or gas displaced by QF's which use no oil or gas, and

         (b) 20% times (1-HRR) for QF's which use some oil or gas, where HRR, the heat rate ratio, is the ratio of the QF oil/ gas heat rate (additional BTU's of oil or gas burned for electric generation per kwh generated) to the average over time of the incremental heat rate from the avoided utility generation.

   b. Utilities whose total sales of electric energy exceeded 500 million kwh during any calendar year beginning after December 31, 1975, shall run a production cost model for the expected load for each hour, and for the expected load plus an increment I, where I is the larger of

      (1) the expected output of the QF with the largest expected output at that time, or

      (2) the smallest calculationally practical increment.

   The avoided fuel and O&M costs for each rating period will be the difference between the cost of carrying the expected load plus

I and the cost of carrying the expected load for the period, which difference shall be divided by the difference in kwh output of the two cases.

c. Utilities whose total sales of electric energy did not exceed 500 million kwh during any calendar year beginning after December 31, 1975, may run a production cost model as described above to determine avoided costs. So as not to unreasonably burden these smaller companies, the utility may, subject to Department approval, specify appropriate plants or purchases of power as the source of its marginal energy for each rating period (peak and off-peak) and determine its avoided energy costs based on these plants' heat rates and the expected price of fuel, or, in the case of purchased power, the cost of that power.

d. The Department shall determine at the first rate setting hearing and at least annually thereafter the variable O&M expenses associated with each marginal plant.

4. The NEPEX adjustment for a time period shall be

$$S \times (E-I)$$

where S = the value per kwh of a NEPEX savings

E = the fraction of the time period during which the utility exports power to NEPEX

I = the fraction of the period during, and which the utility imports power from NEPEX.

Projections of S, E, and I will be based on the best available data. The NEPEX adjustment shall be calculated for each rating period, including an average figure for flat rate purchases.

5. The line loss factor shall reflect the avoided line losses due to operation of the QF. The factor may be averaged over time and over the utility system as computationally necessary. To the extent feasible, the factor will be calculated separately by voltage level, and by

location within the utility system where losses are known to vary by location. The averaging of the factor over time may recognize correlation between avoided percentage losses and avoided generating costs.

The line loss factor (plus one) shall be the best available estimate of the ratio of avoided utility generation requirements (in kwh) to the output of the QF (in kwh). If no better estimate can be produced for a particular application, the line loss factor shall be

$$(1+L)/(1-L)$$

where L is the fraction of utility plant output and non-QF purchases lost between utility plants and customers at the voltage level considered. The Department shall determine at the first rate setting hearing and at least annually thereafter the line loss factors applicable to each utility.

6. For any utility ("retail utility") whose avoided bulk power supply takes the form of power purchased from another utility ("wholesale utility"), the calculation of avoided cost shall reflect the direct savings in decreased purchases and the indirect savings due to reduced rates. The energy purchase rates shall be the sum of a fuel saving and a non-fuel energy saving.

   a. Fuel savings will be calculated based on the following formula, in cents per kwh.

   fuel savings = a + f (m-a)

   where a = average fuel charge from the wholesale utility, including fuel charges in base rates

   m = the avoided fuel cost for the wholesale utility, as defined above for generating utilities

   f = the wholesale utility's sales to the retail utility as a fraction of the total system sales by the wholesale utility

The *a* factor shall include avoided losses on the retail utility system, and the *m* factor shall include all avoided losses on both utilities systems, as defined in paragraph 5, *supra*. Thus, fuel savings shall be in units of cents per kwh delivered by the QF to the retail utility.

b. Non-fuel energy savings shall be the product of the wholesale utility's non-fuel energy charge times the sum of one plus the avoided loss factor for the retail utility, as defined in paragraph 5, supra. However, if the retail utility can conclusively demonstrate that certain costs included in the wholesale non-fuel energy charge will not be reduced or avoided by the wholesale utility, nor transferred to other customers of the wholesale utility by means of increased or extended contract demand or unit sales, and that those costs will to some extent be charged to the retail utility following subsequent rate filings before FERC, then the non-fuel energy savings may be reduced appropriately. In no case may such reduction lower the non-fuel energy savings below to less than

$$1-fxd$$

times the wholesale non-fuel energy charge, where d is a discounting factor (not to exceed unity) reflecting the timing difference between the savings due QF generation and the subsequent change in rates due to such generation, and the resultant time value of money.

C. Required Filings for Energy Rates

Twenty-one days prior to the commencement of the rate setting hearing each utility shall file the following information with the Secretary of the Department for each load case; or, for the utilities who have not exceeded 500 million kwh, for each marginal plant:

1. Expected fuel prices in \$/unit.

2. Expected fuel Btu content in Btu's/unit.

3. Expected system load in the form used to calculate avoided costs.

4. By plant for each month and total for the period: number of hours the plant runs, output in kwh, capacity factor, equivalent availability factor.

5. Planned maintenance schedules.

6. Probability of unscheduled outages by plant.

7. Heat rates by operating level for each plant.

8. Dispatch constraints (must run plants, transmission and distribution constraints, etc.).

9. The avoided cost of fuel per kwh by hour, and by rating period.

10. The aggregate cost of fuel and number of kwh produced in each rating period and the total cost of fuel and number of kwh produced in the period as a whole.

11. Non-fuel wholesale energy charges paid by the utility.

12. A description of the computer model or other calculations from which projected avoided cost was estimated, or a statement that such model or calculation has not changed since the last such description.

13. Actual values of (1)-(5) and (7)-(11) above, and actual periods of unscheduled outage by plant, for the reconciliation period.

D. Capacity Rates

1. Rates for capacity purchased by generating utilities will include, insofar as possible, payment for

a. avoidable reliability-related costs of maintaining generating equipment, including but not limited to costs of

(1) new plants not built,

(2) new capacity purchases not required,

(3) existing purchases which can be reduced,

(4) existing plants whose capacity can be sold,

(5) existing plants which can be retired or sold, or

(6) existing plants which can be rerated to lower levels of operating readiness, such as being placed in seventy-two hour reserve or deactivated reserve;

b. other avoidable reliability-related costs, including but not limited to

(1) costs of outages and voltage reductions to the utility and its customers,
(2) costs of reliability constraints on maintenance scheduling, prompt repair of malfunctioning units, and scheduling of nuclear refueling and
(3) NEPOOL capability charges and credits;

c. avoidable transmission and distribution costs, including but not limited to

(1) costs of transmission or distribution additions which can be deferred or cancelled,

(2) transmission charges which can be reduced or limited, and

(3) costs of transmission facilities associated with avoided generation capacity; and

d. any other avoidable costs not included in the energy rates.

2. The Department recognizes that, whereas energy costs exist and are avoidable on an instantaneous basis, capacity costs are generally only meaningfully defined in the longer

term, on the scale of months and years. Hence, estimates of avoided capacity costs will inevitably reflect a number of discrete, long term events, such as recent or anticipated retirements or deferrals, as well as such continuing benefits as increased scheduling flexibility and reduced loss of load probability. To the extent possible, the Department will set capacity purchase rates so as to give the QF's the best possible price signals regarding their present and future value to the utility system.

Capacity rates will be set on the basis of dollars per kilowatt year, and shall be paid on the basis of cents per kilowatt-hour delivered in the peak period(s), as actually metered or prorated.

3. Capacity purchase rates shall be determined by the Department at the first rate setting hearing and at least annually thereafter. The capacity purchase rate for generating utilities shall equal the NEPOOL Capability Deficiency Charge (plus avoided peak period loss and required reserves) unless some other value can be shown to be more reasonable.

4. Retail utilities (as defined in §IIBG *supra*) shall determine their capacity purchase rate for QF's by reference to the demand change in the applicable wholesale rate of their wholesale supplier. In such cases, the capacity purchase rate shall equal the wholesale capacity charge unless the retail utility can demonstrate that certain portions of the wholesale change should not be paid to the QF, for the reasons discussed in §IIBGb *supra* with reference to non-fuel energy changes, and subject to the same requirements and limitations as found in §IIBGb. In no case shall the capacity purchase rate for a retail utility be less than the capacity purchase rate applicable to its wholesale utility under §IID3 *supra*.

5. All QF's which provide power to the utility on the basis of simultaneous purchase and sale shall be paid for capacity, as shall all QF's which are net sellers metered by time of supply. Except as otherwise provided herein, QF's metered by time of supply will be paid at a single flat rate per kwh in each peak period, while QF's not so metered will be paid at a single flat rate per kwh in each month. Such rates will be determined as the quotient of the capacity cost allocated to the period, divided by the hours in the period.

4. The Department shall determine at the first ratesetting hearing, and at least annually thereafter,

a. the portion of annual capacity value to be allocated to each month,

b. the portion of each month's capacity value to be allocated to each rating period,

c. the weighting of the avoided loss factor within the rating period for the purpose of deriving the avoided loss factor for capacity, and

d. whether the previously established annual capacity value should be changed.

F. There shall be no charge for wheeling energy and capacity from qualifying facilities, to any utility interconnected with the wheeling utility. Any utility to which power from a QF is provided, directly or indirectly, shall at the request of the QF, wheel such power to any interconnected utility.

III. Interconnection Costs, Monthly Charges, and Terms

All interconnected costs and monthly charges will be based on the incremental cost to the utility.

A. Interconnection

The qualifying facility shall reimburse the utility for the full cost of interconnection, including meter installation. The interconnection costs may be amortized over a period of up to the useful life of the equipment, with the period of amortization chosen by the qualifying facility. In such a case the facility will pay a monthly charge designed to recover the interconnection costs plus the cost of carrying these expenses over the period of amortization. The qualifying facility may instead pay all interconnection costs at the time of interconnection if it so chooses.

B. Metering

For a qualifying facility to receive payment or credit for energy delivered to the utility all such energy must be separately metered. The qualifying facility shall furnish and install the necessary meter socket and wiring in accordance with reasonable and accepted electrical standards. If the facility supplies more than 40 Kw to the utility, a time-of-day meter shall be used. Unless the qualifying facility agrees to other terms, such meter will be the least expensive meter generally available which can record sales to the utility in the appropriate time periods. The utility will install, read, and maintain the metering equipment. Where the qualifying facility chooses to own the metering equipment, the facility will pay the invoice cost to the utility of the meter, plus a monthly charge to cover maintenance. Where the utility owns the meter, the qualifying facility will pay a monthly charge which covers the maintenance on the meter, the return on the invoice cost of the meter, and the depreciation of the meter. There will be a monthly charge for the utility's incremental cost of meter reading and billing. The qualifying facility may choose to receive a check from the utility as payment for power supplied or may have the payment credited against the bill for power from the utility.

C. Safety

An initial safety inspection of the facility's equipment before interconnection may be required by the utility. Such inspection shall be paid for by the qualifying facility. Generic safety or certification of generators on intercorrection equipment shall be performed by the utility at the request of the equipment manufacturer or any agent thereof.

The utility may periodically inspect, test, and certify in the writing the qualifying facility's compliance with reasonable safety standards. These standards shall include the provision that the qualifying facility's equipment must prevent the flow of electricity into the utility's system when the utility's supply is out of service. There will be no charge to the qualifying facility for these inspections unless it is an inspection to ascertain whether repairs, if required, have been effected.

D. Required Filings

All charges described in this part (section III) will be determined at least annually by the Department. The utilities must file proposed charges for the Department's approval and must file data and work