EPA United States Environmental Protection Agency

Region I
JFK Federal Building
Boston, MA 02203

Taunton Energy Center
(150 MW Coal-Fired Cogeneration Plant)
Taunton, Massachusetts

Environmental Assessment
July, 1992

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1.0 INTRODUCTION

Under the Clean Water Act, the direct discharge of pollutants to waters of the United States requires a National Pollutant Discharge Elimination System (NPDES) permit. Silver City Energy Limited Partnership (LP) is seeking from the U.S. Environmental Protection Agency, Region I, Boston (EPA), an NPDES permit for the discharge of plant cooling water and treated process wastewater from its proposed Taunton Energy Center (TEC) in Taunton, Massachusetts. New Source Performance Standards (which contain specific numerical limitations for various categories of wastewater streams) have been promulgated for discharges from new steam electric power plants and EPA has determined that the proposed Taunton Energy Center would be a "New Source" as defined in the Clean Water Act. Section 511 of the Clean Water Act stipulates that the provisions of the National Environmental Policy Act (NEPA), 42 USC 4321 et. seq., apply to the issuance of "New Source" NPDES permits.

The role of the EPA is to evaluate the environmental consequences of the proposed action in order to determine whether to issue or deny a National Pollutant Discharge Elimination System (NPDES) permit for the facility. EPA's NEPA environmental review procedures for the New Source NPDES program are found at 40 CFR Sections 6.600 - 6.607. Under these regulations, EPA must evaluate the potential direct, indirect, and cumulative environmental impacts that would be associated with construction and operation of the proposed facility and determine whether or not significant impacts are anticipated. If significant impacts are predicted, a more detailed Environmental Impact Statement (EIS) must be prepared, as discussed in 40 CFR Section 6.604. EPA has prepared this Environmental Assessment (EA) to serve as a tool in determining whether or not significant impacts are anticipated from this proposed action and to assist in identifying alternatives which could avoid or mitigate potential adverse impacts.

Documents reviewed by EPA in preparation of this EA include the Draft and Final Environmental Impact Reports (February 15, 1991 and July, 1991 respectively) submitted by the project proponent to the Massachusetts Executive Office of Environmental Affairs for the purposes of review under the Massachusetts Environmental Policy Act (MEPA), the "Petition Before the Massachusetts Energy Facilities Siting Council for Approval to Construct a Bulk Generating Facility", and other associated documents and information provided by the applicant (see Section 10.0 for a complete list of references). In addition, EPA has consulted with various other state and federal officials on this proposal. This Environmental Assessment presents the findings of our independent environmental review in accordance with NEPA.

2.0 PROPOSED ACTION

Silver City Energy LP, comprised of Constellation Energy, Inc. of Baltimore, Maryland, PG&E/Bechtel Generating Company, of Bethesda, Maryland, and Cogeneration Services Corporation of Plymouth, Massachusetts, proposes to build the Taunton Energy Center, a 150 megawatt (MW) Circulating Fluidized Bed (CFB) coal-fired cogeneration plant.

The project will be located on property leased from the Taunton Municipal Lighting Plant (TMLP), adjacent to the Taunton River and to TMLP's existing Cleary Flood Generating Station (Figure 2-1). By generating both electricity and steam for use, the plant is able to qualify for favorable regulatory treatment as a cogeneration facility under The Public Utility Regulatory Policies Act (PURPA). Most cogenerators choose to locate near an industry with an identified need for and willingness to purchase steam from the proposed facility. In this case, a carbon dioxide plant is proposed to be constructed adjacent to the plant to extract food-grade carbon dioxide from stack gases and to serve as the steam host.

Wet cooling towers, employing makeup water from the Taunton River, will be utilized for cooling. An average of 1600 gallons per minute (GPM) will be withdrawn from the river utilizing an existing pump house. Approximately 310 GPM of cooling tower blowdown and small amounts of treated process wastewaters will be returned to the river through an existing 1,700 foot discharge canal that services the Cleary Flood Generating Station.

Coal will be transported to the plant by rail along an existing rail right-of-way on existing track to be reconstructed for this purpose. Approximately one 80 car coal train will arrive per week. The facility will consume approximately 1,470 tons per day of coal. Limestone will be transported to the plant by truck or rail and stored in silos prior to use. Pelletized bottom ash and fly ash will be transported off-site by rail to a licensed disposal site out of state by the contracted fuel supplier, or to an industrial user if one can be established.

It is estimated that the plant will generate the following emissions (from Taunton Energy Center, 1991c):

Nitrogen Oxides (NO_x):	1004 tons per year
Sulfur Dioxide (SO_2):	1713 tons per year
Particulate Matter:	125 tons per year
Carbon Monoxide:	1205 tons per year
Non Methane Hydrocarbons:	49 tons per year

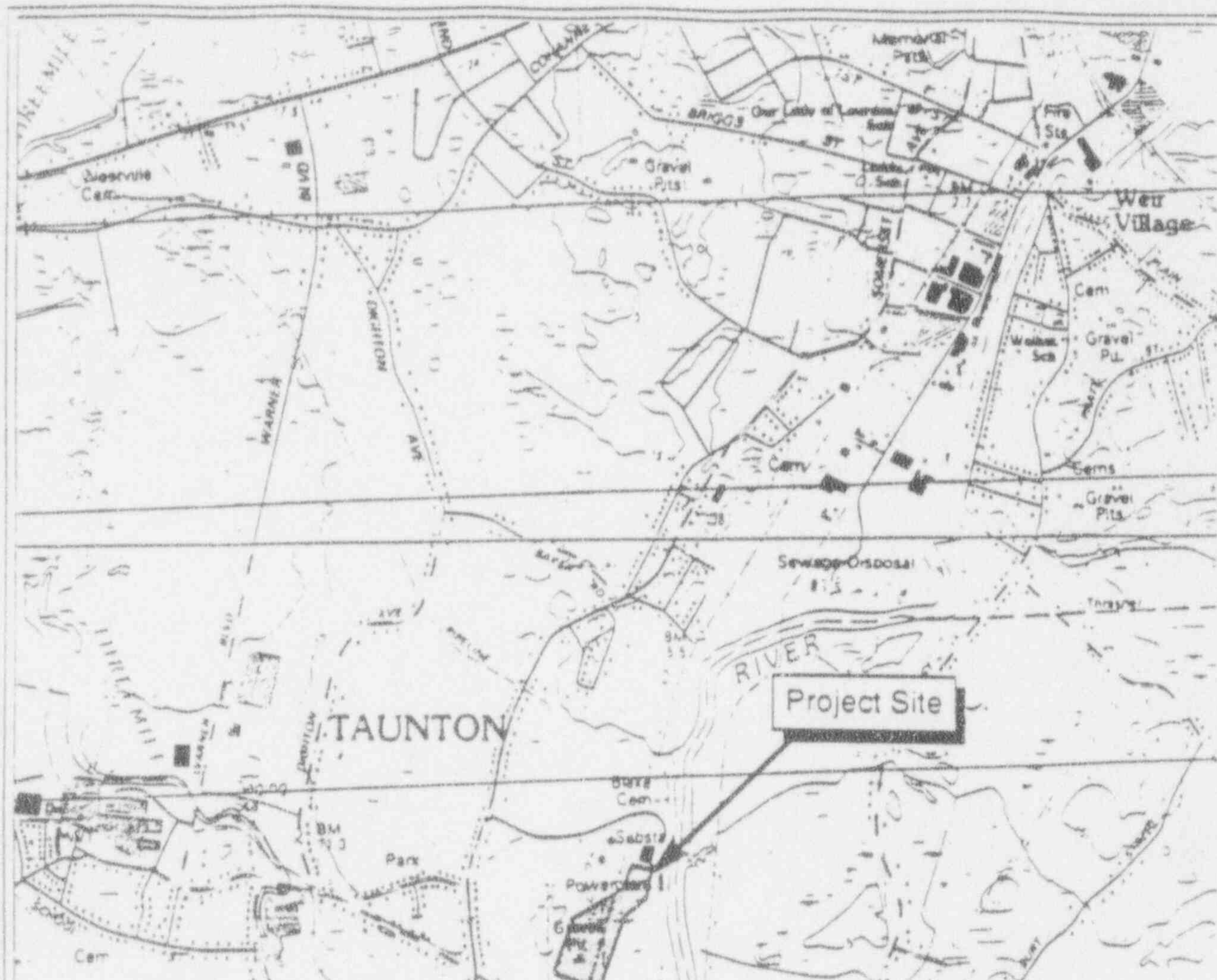

FIGURE 2-1
SITE VICINITY MAP

Source: Taunton Energy Center, 1991b. Draft Environmental Impact Report for the Taunton Energy Center. Prepared by HMM Associates, February, 1991. Concord, MA.

The sewer line to be built for the project will be approximately 4,900 feet long. It will extend from Railroad Avenue, south of the project, north to a connection to the Taunton Municipal Sewer at Baker Avenue. The sewer extension to Railroad Avenue has been made a condition of Site Plan Approval by the City of Taunton. This will permit the eventual sewering of homes on Railroad Avenue, which are now served by on-site septic systems.

The sewer line will be a forced main, with a pump station at Railroad Avenue and a lift station by the existing TMLP plant to accommodate flows from that facility. The sewer line will be constructed on the edge of the existing railroad embankment using standard trenching equipment, which will be brought along an existing haul road on the edge of the tracks. It will cross two existing culverts that traverse the embankment.

3.0 PROJECT PURPOSE AND NEED

NEPA regulations state that the EPA shall clearly specify the underlying purpose and need to which the agency is responding; if the action is a request for a permit, EPA must also specify the goal and objectives of the applicant (40 C.F.R. §6.203(a)). Although the underlying purpose and need for EPA action on the proposed project is to respond to the proponent's NPDES permit application, under NEPA, EPA is required to include in its decision-making process appropriate and careful consideration of the need for the project and all environmental effects of proposed actions and their alternatives for public understanding and disclosure.

The "need" for particular power generating facilities can be assessed from several perspectives: (1) whether the power is needed in an absolute sense to satisfy present or future energy demands; (2) whether a particular type of power production facility is needed to provide an appropriate mix of facility types to avoid over-reliance on a particular fuel source or to ensure an appropriately efficient or clean power supply; or (3) whether certain types of new facilities are needed to ensure an appropriately reliable power supply given the remaining useful life of existing facilities. Thus, even if enough power production capacity exists to meet demand at any given time, for a variety of reasons there may be a need for new facilities to be built to replace some portion of the existing capacity.

Therefore, determining if and when an electric generating facility is needed is a complicated and evolving process. Legislation and policy directives at both the federal and state levels influence the decision-making process. In preparation of this document, EPA examined federal and state regulations pertaining to the review and siting of cogeneration facilities. These laws and policies include the federal Public Utility Regulatory Policies Act (PURPA) and individual state utility regulations.

Because EPA has no independent statutory authority to determine the need for additional electrical generating capacity within a state or region, EPA's evaluation of need for electric generating facilities such as the proposed Taunton Energy Center necessarily relies upon the policies and decision-making processes of the agencies that are given such authority under state and federal energy laws.

Following a brief discussion of the goals and objectives of the applicant, the remaining parts of this section attempt to provide the reader with an understanding of the process by which the need for power, the need for specific types of power generation, and acceptable costs of power procurement are assessed and determined under federal and state laws.

3.1 Goals and Objectives of the Applicant

In the Draft Environmental Information Report (DEIR) prepared in January of 1991, Silver City Energy L.P., the project proponent, stated that the purpose of the proposed project is to use steam created through the combustion process at the facility to generate 150 MW of electricity. The Taunton Energy Center project was later tailored to respond to an RFP from TMLP for an electricity generating facility meeting the conditions of being adjacent to the Cleary Flood Station and employing coal-fired technology.

A portion of the steam (47,000 lbs/hour) produced by the TEC is to be extracted from the turbine for use at an on-site carbon dioxide plant. CO_2 will be stripped from the plant's stack gas and converted to food-grade CO_2 for resale. The sale of CO2 is a secondary purpose of the project, while the primary purpose is the sale of electricity. By generating both electricity and steam for use, the plant is able to qualify for favorable regulatory treatment as a cogeneration facility under PURPA.

In their DEIR, the proponent stated that the market need for the electricity generated from the project was based primarily on significant projected annual shortfalls of capacity within New England commencing in the mid-1990's. Details of the process by which the state evaluates such power projections is discussed in further detail below.

3.2 Policy and Regulatory Framework

3.2.1 The Public Utility Regulatory Policies Act of 1978

The Public Utility Regulatory Policies Act (PURPA) was enacted in 1978 to, among other things, encourage the development of cogeneration and small power production by loosening the economic, regulatory, and institutional barriers that had discouraged their development, and by actually creating incentives to encourage cogeneration and the use of renewable energy resources.

Administration of PURPA's programs was placed under the authority of the Federal Energy Regulatory Commission (FERC). 18 C.F.R. Part 292 of the FERC regulations established under PURPA deals with small power producers and cogeneration. Small power producers are those facilities with a capacity under 80 megawatts which use renewable energy such as biomass or geothermal sources. In 1990, for specific energy sources (waste, solar, geothermal, and wind), the size limitation to qualify as a small power producer was removed.

Cogeneration facilities (like the TEC) do not have a maximum size or fuel requirement, but must produce a minimum of 5 percent thermal energy output. Additional requirements are enforced if any of the energy input to the facility is from oil or natural gas, because PURPA was intended to help address the oil and gas energy crisis of the mid-1970s by encouraging the use of renewable resources and coal.

Small power producers and cogeneration facilities may become "qualifying" facilities (QFs) under PURPA if they meet the applicable criteria of maximum size, fuel use, operating and efficiency standards, and ownership requirements in the regulations. On October 29, 1991, Silver City Energy L.P. filed a <u>Notification of Self-Certification of a Facility as a Qualifying Cogeneration Facility</u> with the Federal Energy Regulatory Commission. This filing empowers the project proponent to operate as a qualifying cogeneration facility under PURPA.

Subpart C of the PURPA regulations addresses sale and purchase arrangements between electric utilities and qualifying cogeneration or small power production facilities. These regulations require that utilities purchase energy and capacity from qualifying facilities under specified conditions (see 18 CFR 292.303). A utility in need of additional power is obligated to purchase power from a qualifying cogenerator if purchase rates are just and reasonable to the electric consumer and are equal to or less than the utility's avoided cost, which is the incremental cost that an electric utility would incur to produce or purchase an amount of power equivalent to that purchased from QFs. However, a utility is not forced to purchase power from cogeneration facilities, even if they meet the utility's avoided cost, unless the utility has solicited proposals.

According to the regulations, factors affecting rates for purchase include the availability of capacity or energy from a QF during system daily and seasonal peak periods; the relationship of the availability of energy or capacity from the QF to the ability of the electric utility to avoid costs, including the deferral of capacity additions and the reduction of fossil fuel use; and the costs or savings resulting from variations in line losses from those that would have existed in the absence of purchases from a QF.

The intent of PURPA was to foster the development of non-utility cogeneration plants nationally in order to address the 1970's "energy crisis" and to increase efficiency and reliability of the nation's power supply. In a general sense, therefore, there is a federally declared "need" for cogeneration plants which comply with PURPA and state regulations, and which meet the economic conditions set out in PURPA and the regulations adopted under PURPA. The individual states, however, were left by Congress with the authority to determine the need for particular electric generating facilities under their jurisdiction. The general process employed by the state of Massachusetts is described below.

3.2.2 Regional Power Planning

The New England Power Pool (NEPOOL) is a coordinated group of utility systems in New England which own, control, or utilize over 99 percent of all the region's electrical generation. The NEPOOL Agreement is a voluntary agreement among electric utility systems in New England. The objectives of NEPOOL are to assure that the bulk power supply of New England conforms to proper standards for reliability, to attain maximum practicable economy, and to provide for the equitable sharing of the resulting benefits and costs (NEPLAN,1991).

NEPOOL's responsibilities include forecasting total New England loads, joint planning of power supply and transmission facilities, maintenance of generating reserves, central dispatch of all generating units, and joint use of transmission facilities. NEPOOL operates the region's electric grid on an hour-by-hour basis. Participating members relinquish their control to NEPOOL, which dispatches power to meet demand (NEPLAN, 1991). As demand changes during the day, NEPOOL orders plants to either increase or decrease their output. The decision about which plants to call upon is an economic one based upon which plants are the least expensive to operate within system operational reliability and transmission constraints. Therefore, the least costly plants to operate are called upon first to produce extra power and the most costly plants to operate are the first to be ordered to decrease output, as demand requires (Moskowitz, 1990). The costs considered by NEPOOL are only the operating costs, not capital costs. The elements of the cost include fuel, age, and operating efficiency of particular facilities. Environmental costs are not part of the calculation (Moskowitz, 1990).

To accomplish its task of making sure that adequate capacity (plus contingency) and energy are available on a daily basis in base and peak periods, NEPOOL completes a variety of short and long-term projections. Several committees are established under the NEPOOL umbrella to accomplish this. The Load Forecasting Committee is charged with projecting New England peak load and energy forecast for a 15 year planning period. The Demand Side Management (DSM) Planning Committee develops recommendations on the quantification and integration of NEPOOL participant (non-utility and utility) DSM programs into the planning process (NEPLAN,1991). DSM measures seek to ensure adequate supply to meet demand by controlling demand rather than by increasing supply. The Power Supply Planning Committee studies, coordinates, and evaluates the NEPOOL participants' alternative plans of power supply expansion (NEPLAN, 1991). These activities result in reports which provide guidance for utilities for use in the planning process (Chan, personal communication, 1992).

The process used to forecast energy and capacity demands is based upon several modeling tools and includes short-term and long-range planning. A major component is evaluating the risk of insufficient generating capacity. The on-line generating capacity must, at all times, be sufficient to meet the constantly varying instantaneous regional demand for power (NEPLAN,1991).

As noted above, NEPOOL incorporates proposed demand side management programs into its base and peak load forecasts. DSM programs can be either efficiency or conservation programs which effectively reduce the total load demand, or peak load management, which shifts the peak load to another period. This enables the utility to maintain more constant levels of demand, reduces demand peaks, and reduces the need for power production.

Cost-effective, environmentally sound demand side management programs can reduce the need for construction of new power sources. DSM is an energy management technique and is part of a utility's overall planning structure to meet future demand. Most states require that utilities undertake least cost planning to provide the lowest possible rates to ratepayers, so the relative costs and energy efficiency gains of DSM measures are taken into account. This is so in Massachusetts, as discussed below.

The forecasts of DSM by NEPOOL are the result of an annual data collection effort by the NEPOOL DSM Planning Committee and NEPOOL staff. The 1991 NEPOOL report included a data base of over 400 DSM programs in place or planned at 21 reporting Participant Utilities (representing nearly 95 percent of NEPOOL Load) (NEPLAN, 1991).

Forecasted DSM impacts at NEPOOL summer peak are expected to grow to 3440 MWH by the year 2006. Approximately 10,400 GWH are forecast to be saved cumulatively by 2006, a 30 percent increase over NEPOOL's previous forecast. Thus, existing DSM programs and projected growth in DSM programs are taken into account by NEPOOL. However, NEPOOL notes that DSM program planning is ongoing and evolving and thus variations in year to year estimates are to be expected (NEPLAN, 1991).

3.2.3 Massachusetts Regulatory Process

In response to the policy mandate of PURPA, Massachusetts and other New England states developed their own policies and rules regarding the role of non-utility electric generation in their mixture of power production facilities and DSM measures. Like most other New England states, Massachusetts requires that utilities undertake "least cost planning" which means developing the practicable mix of DSM and new power supply that yields the lowest cost to the ratepayers.

In Massachusetts, decision-making in regard to determining the need for additional generating capacity is guided by the newly enacted (1990) Massachusetts Integrated Resource Management (IRM) Policy and Regulations. Both the Massachusetts Department of Public Utilities (DPU) and the Massachusetts Energy Facilities Siting Council (EFSC) implement IRM policy and directives, and are ultimately responsible for determining whether or not an additional energy supply source is needed within the state.

Briefly, as related to the question of need for additional generating capacity, the IRM process works as follows. Utilities are required to identify their current and future capacity needs and submit a filing of such to the EFSC every 18-30 months for approval. The filing must include a demand forecast, a resource inventory, and a resource need and technical potential evaluation. IRM regulations mandate consideration of demand side management and conservation programs during this process. The EFSC must approve a utility's filing and concur with its determination of need for additional capacity before the utility can receive approval to issue an all-resource solicitation for the purchase of additional power.

Concurrently, the utility files with the DPU a draft Request for Proposals (RFP) which defines the criteria the utility will employ to select a power supplier from the proposals received to fulfill its established need (the RFP may be revised after EFSC approval of resource need). DPU approval of an RFP is required before it can be released to the public and potential bidders. Utilities review all offers received in response to their RFPs and may execute contracts with one or more bidders in order to fulfill their needs. The DPU reviews and must approve final contracts between utilities and non-utility generators in order for the contracts to be effective.

Massachusetts IRM regulations require that the project selection ranking system in an RFP include environmental externalities (e.g., air quality impacts). Environmental externalities are defined as the value of environmental damage (or impacts) caused by a project or activity for which compensation to affected parties does not occur, regardless of where those damages occur. Regulations also require that the all-resource solicitations put out by utilities be for both supply side and demand side resources. The proposals must be evaluated using the same criteria, which means that demand side management measures have an equal opportunity to be selected.

The TEC project was developed by Silver City Energy LP in response to a non-IRM RFP issued in 1989 by the Taunton Municipal Light and Power (TMLP), for development of a new coal-fired facility adjacent to the existing TMLP Cleary Flood Station. The project proponent has executed a municipal contract with TMLP for sale of 30 MW of the plant's output. Thus, in one sense, a need for a portion of the TEC project's power production has been evidenced.

However, municipal utilities in Massachusetts are subject to different review requirements than non-municipal utilities. EFSC reviews a municipal utility's RFP process and contract to determine if it represents least cost (this will be done for the TMLP contract). Yet, even if it does not represent least cost, the contract is still valid; however, only if the contract is approved by EFSC as least cost will Silver City Energy be allowed to rely on possession of the contract to establish need under the EFSC review process.

Although there is a small possibility that TEC could negotiate other non-IRM contracts to sell the remaining 120 MW the plant will produce, it is much more likely that the remaining 120 MW will be made available for sale to other Massachusetts utilities, in accordance with IRM regulations noted above. Any contracts with utilities would fall under the IRM process, while any additional municipal contracts would be subject to EFSC review as part of the municipal forecast review process. If TEC is unable to obtain contracts to sell the rest of the power it plans to produce, the facility will not be financially viable and it will not be built. Both state regulators and the project proponent have confirmed this fact to EPA.

3.2.3.1 EFSC Review Process for Non-Utility Generators (NUGs)

As with all facilities capable of supplying greater than 100 megawatts of power, before construction of the Taunton Energy Center may begin, the EFSC must review and approve the proposal. The EFSC is responsible under M.G.L.c. 164 §69H for ensuring that sufficient energy supplies are available to the Commonwealth with minimum environmental impact and cost. The EFSC considers the need for new facilities on both a New England regional and state-wide basis.

A project proponent in Massachusetts must demonstrate the need for its power to the EFSC either directly, through signed power sales agreements with Massachusetts utilities, or indirectly, through regional need analysis and demonstration of other benefits accruing to the Commonwealth. These benefits may include:

- Location/Transmission Benefits (e.g. location of a source near power demand loads)
- Economic Efficiency Benefits (e.g. power is available at or below a utility's avoided cost)
- Reduced Environmental Impacts (as compared to existing and alternative forms of energy -- especially where the cogeneration project would allow the steam host to shut down old boilers)
- Fuel Diversification (e.g. less reliance on imported oil)

The EFSC also requires that any new non-utility generator (NUG) be economically viable and able to meet performance objectives and the terms of any power sales agreements. Finally, the EFSC requires NUGs to demonstrate that the sites for their proposed facilities are superior to alternatives, and to minimize environmental impacts and costs. To meet this requirement, a NUG must develop a set of siting criteria for identifying and evaluating alternatives to their proposed action.

Silver City Energy LP submitted a petition to the EFSC in February, 1991 for approval to construct the TEC. This petition is intended to demonstrate that the TEC fully complies with EFSC requirements for approval of a NUG facility. This petition is still under review by the EFSC and it is expected that a decision will be issued in the late summer or early fall of 1992 (LaCompt, personal communication, 1992).

3.3 Need for the TEC to Meet New Power Demand

Under PURPA and under state utility regulations, a policy is established that cogeneration facilities are needed as part of least cost planning if the cost of their development would be less than other alternative options to provide the same capacity. It is up to the state, through the processes described above, to decide, based on all the issues, whether utilities need the power the Taunton Energy Center would produce.

EPA has no independent statutory authority to assess the need for additional electrical generating capacity in the region. It is up to the state to decide, through the processes described above, whether after considering all the pertinent facts and issues, the power the Taunton Energy Center would produce is needed. EPA's proper role, as presented in this EA, is to discuss the components of the evaluation of need, to explain the general need for cogeneration power production under federal energy policy that the TEC is intended to meet, and to assist the public in understanding the process by which state energy regulatory agencies will ultimately determine the specific need (or not) for the new electric generating capacity of the proposed TEC facility.

Thus, EPA has not determined that there is a specific need for this facility, but has determined that federal energy policy generally favors qualifying cogeneration facilities like TEC. The specific need for this facility will be determined by the state EFSC siting and IRM processes. The Massachusetts EFSC siting review process (including EFSC review of the TMLP contract) requires a rigorous evaluation of project need and site-specific environmental effects, and therefore is an important complement to EPA's role in project review on the issue of energy needs, as well as other issues. EPA expects that the EFSC review process will be sufficient to determine whether or not TEC's as yet unobligated 120 MW is needed: If the project proponent cannot successfully negotiate power sales contracts with interested utilities at or below their avoided costs, or is unable to survive the EFSC approval process, the facility will not be built.

4.0 ALTERNATIVES

NEPA regulations require EPA, during environmental review, to explore a reasonable range of siting and technology alternatives, including the no build alternative. EPA's review is intended to determine whether any substantially preferable alternatives to the proposed action exist. The analysis of alternatives for the proposed Taunton Energy Center is summarized below.

4.1 Alternative Sites

As part of the review process established by the Energy Facilities Siting Council, the project proponent is required to evaluate a reasonable range of alternatives to the proposed project, and demonstrate, through a comprehensive site selection process, that a clearly superior site has not been overlooked or eliminated. The EFSC evaluates potential alternatives with regard to their environmental, cost, and reliability impacts. In its review of this project, EPA is also required to determine whether the applicant evaluated a reasonable set of alternative sites, given their goals and objectives for the project. EPA's review is intended to determine whether the proposed action is environmentally acceptable and whether any substantially preferable alternatives to the proposed action exist.

The proponent conducted systematic analyses to (1) identify opportunities for NUG development within New England; and (2) select a suitable site for project development.

Initially, the proponent applied a broad set of project development criteria to identify a primary target area, or market, for the proposed NUG project. These initial criteria included:

- o Regional and local electrical generation demand
- o Potential for co-location with a suitable steam host
- o Environmental compatibility of sites (for all key impacts)
- o Community acceptance of project

When these criteria were applied to the New England region, the applicant selected the southeastern Massachusetts area as the primary "target area" (Silver City Energy, 1991b). Within this region, five sites were initially identified as promising:

- o Ocean Spray (Plymouth)
- o Plymouth Industrial Park
- o Cordage Park
- o Braintree Electric
- o Miles Standish Industrial Park

During the process of analyzing these sites, the proponent learned of an impending Request for Proposals (RFP) for NUG capacity issued by TMLP. The proponent elected to focus upon available sites within the TMLP service territory, including the proposed location, in order to be responsive to the TMLP RFP requirements (Silver Center Energy, 1991b).

After selecting the TMLP RFP and service territory as their target area, the proponent developed a new site screening process in order to respond to the requirements of the Massachusetts EFSC filing process. In their EFSC petition, the proponent presented and documented a three-tier site selection process. This process involved (1) development and use of broad search criteria to identify potential alternative sites; (2) application of more specific site screening criteria to select the two highest-ranked alternative sites; and (3) development of weighted evaluation criteria to identify the environmentally preferred site. This process is summarized below (see TEC, 1991d, for details).

The initial site search criteria included the following:

- o Site Compatibility: Suitability of the proposed facility with existing and future adjacent land uses

- Sufficient Upland Area: Availability of flat, non-wetland acreage on the site

- Potential Rail Access: Proximity to existing rail lines, for shipment of coal and ash to/from site

Using these criteria, a total of 13 sites were initially identified by the applicant. Seven of these sites were subsequently eliminated, due to excessive rail grades (preventing rail access), excessive wetlands impacts (greater than 5000 sq. ft. of bordering vegetated wetlands) and incompatibility with surrounding land uses.

The remaining six sites included five locations in Taunton and one in Raynham. These sites included:

- Miles Standish Industrial Park (Taunton)
- Route 140 Industrial Park
- West Water Street (former TMLP plant site)
- North Raynham site
- E. Taunton Industrial site
- TMLP Cleary Flood Station (preferred site)

These sites were evaluated using five screening criteria, in order to identify at least two sites for more detailed evaluation (pursuant to EFSC requirements). These screening criteria focus on the potential for significant construction and operational impacts resulting from the proposed facility. They include:

- Site Compatibility: Potential for noise, visual, traffic and other impacts to adjacent land uses

- Minimization of Wetlands Impacts: Ability to avoid and/or minimize wetlands for the facility layout

- Rail Access: Proximity to rail lines, and impacts from rail operations on surrounding land uses

- Availability of Water Supply: Access to plant "make-up" water and discharge receiving water

- Transmission Line Access: Availability of 115 kv transmission lines and right-of-way to site

The proponent applied these screening criteria to the six sites, and ranked the alternatives as shown in Table 4-1. Only two sites, the TMLP Cleary Flood Station and the Miles Standish Industrial Park, emerged with positive scores (reflecting their relatively high ranking). These sites were therefore carried through to a final site screening process, which involved a more detailed evaluation of environmental, cost, and reliability impacts for each alternative.

Table 4-1

APPLICATION OF SCREENING CRITERIA

	Site 1	Site 2	Site 3	Site 4	Site 5	Site 6
Site Compatibility	0	0	+	-	-	+
Minimization of Wetland Impacts	+	-	-	+	-	+
Rail Access	+	0	-	-	0	0
Available Water Supply	0	-	+	-	+	+
Transmission Line Access	0	0	0	-	-	+
Total Score	+2	-2	0	-3	-2	+4

Key: +1 = Well suited
0 = Minimally suited
-1 = Poorly suited

Site 1 = T1 Miles Standish Industrial Park Expansion Area
Site 2 = T2 Route 140 Industrial Park Area
Site 3 = T3 TMLP West Water Street Plant and Adjoining Property
Site 4 = R1 North Raynham Area
Site 5 = T5 East Taunton Industrial Area
Site 6 = T6 Cleary Flood Station Property

Source: Taunton Energy Center, 1991d. Response to EPA Comments on the Taunton Energy Center. Prepared by HMM Associates, June, 1991. Concord, MA.

The final set of evaluation criteria which were used addressed a more comprehensive set of potential environmental impacts than earlier screening. These final criteria included:

- o Site Compatibility
- o Wetlands Impacts
- o Rail Access
- o Water Availability
- o Transmission Line Access
- o Air Quality
- o Groundwater/Floodplains
- o Steam Host Potential
- o Socioeconomic Impacts
- o Ecological Impacts
- o Transportation Access
- o Cultural Resources

The proponent weighted these criteria (based upon a subjective evaluation of their importance to siting), and ranked both sites according to these criteria. This resulted in a weighted score for each criterion and a total aggregate score which favored selection of the TMLP Cleary Flood Station (Table 4-2). This site also was preferred from a cost and reliability standpoint, and was thus selected by the proponent as the preferred site in the EFSC Petition.

EPA conducted an independent review of these criteria, and the proponent's weighting of each criteria. While the chosen criteria encompass the key issues which are properly applied to facility siting decisions, the weighting of criteria is necessarily a subjective exercise. For this reason, the weighting of selection criteria can skew a site selection process. EPA evaluated and scored the two sites, using the stated criteria, but with independent scoring and no weighting of criteria. The results of this evaluation indicated that the relative scores of the proposed site and the Miles Standish site were closer than that indicated by the proponent, with the sites emerging as approximately equal. Neither site was found to have any environmentally unacceptable attributes.

Because both alternative sites are environmentally acceptable and the Miles Standish site did not emerge as a substantially preferable alternative to the proposed action (on the basis of our scoring), and did not respond to the TMLP RFP requirements (location in proximity to the Cleary Flood Station), the proposed action is considered to be an acceptable siting alternative.

4.2 Alternative Power Generating Technologies

The project proponent was specifically directed within the RFP issued by TMLP to utilize coal-combustion technology for their

Table 4-2

WEIGHTING/RANKING OF TWO ALTERNATIVE SITES

	Criteria	Miles Standish Site			TMLP Cleary Flood Site		
		Rank	Weight	Score	Rank	Weight	Score
1.	Site Compatibility	2	15	30	2.5	15	38
2.	Wetlands	2.7	15	41	2.7	15	41
3.	Rail Access	2.5	15	38	2.3	15	35
4.	Water Availability	1.7	10	17	3	10	30
5.	Transmission Line Access	2	10	20	3	10	30
6.	Air Quality	3	5	15	3	5	15
7.	Groundwater/Floodplain	2.7	5	14	3.0	5	15
8.	Steam Host Potential	2	5	10	1	5	5
9.	Socioeconomic	1	5	5	3	5	15
10.	Ecology	3	5	15	3	5	15
11.	Transportation	3	5	15	2	5	10
12.	Cultural Resources	3	5	15	3	5	15
				235 / 300			264 / 300
				= 78%			= 88%

Source: Taunton Energy Center, 1991d. Response to EPA Comments on the Taunton Energy Center. Prepared by HMM Associates, June, 1991. Concord, MA.

proposed facility; all other technologies would not be considered responsive to the RFP (Taunton Energy Center, 1991b). The proponent selected the circulating fluidized bed (CFB) combustion technology in view of its inherent combustion efficiency and reduction/control of key pollutants, including sulfur dioxide and particulate matter. However, as part of the EFSC review process, the proponent also evaluated the alternative of a 150-MW gas fired combined cycle (GFCC) facility at the preferred site.

As part of this analysis, the GFCC alternative was compared with the proposed coal-fired facility with regard to estimated annual emissions, based upon expected periods of operation within the NEPOOL energy pool. In terms of projected annual emissions, the GFCC alternative would be expected to release significantly less pollutants than the CFB, as shown below in Table 4-3, due to the lower emission rates of gas-fired technologies.

The proponent's analysis also estimated that the use of a GFCC facility would result in a higher amount of avoided emissions (i.e. displacement of older, less efficient plants) from the NEPOOL energy grid, for nitrogen oxides, carbon monoxide, and VOCs. By contrast, the proponent estimated that CO and VOC emissions would increase from operation of the CFB plant (though not at levels that would exceed applicable air quality requirements), although slightly more sulfur dioxide and particulate emissions would be avoided with use of CFB technology (see Table 4-4).

The proponent estimated in its analysis that a GFCC facility would run less frequently (due to higher fuel costs) than the CFB facility, and would thus displace less older high-emission plant capacity. It should be noted, however, that the predicted amounts of annual emissions from the project (and of emissions avoided from other plants) are based upon NEPOOL's decision-making process for dispatching individual units, and actual emission levels will thus depend upon prevailing fuel supply conditions (e.g. coal and gas price and availability) and power demand requirements once the facility is constructed. For this reason, it is not possible to conclusively demonstrate that the proposed facility will result in lower net emissions than a GFCC facility.

Based upon available data on other comparably-sized gas facilities, it is likely that a GFCC facility, if operated on an equivalent dispatch basis as a coal facility, would contribute less pollutants to the region. In fact, much of the air quality impacts from a GFCC facility result from the projected use of No. 2 fuel oil on a limited basis, as a back-up to natural gas. Therefore, although both a CFB and a GFCC facility are environmentally acceptable

Table 4-3
PROJECTED ANNUAL EMISSIONS FOR CFB AND GFCC FACILITIES OPERATING WITHIN NEPOOL, 1995-1999

	GFCC	CFB (coal-fired)
SO_2	211 tpy	1427 tpy
NO_2	141 tpy	836 tpy
Particulate	67 tpy	100 tpy
CO	82 tpy	1004 tpy
VOC	12 tpy	39 tpy

Source: Taunton Energy Center, EFSC Petition, Tables 4-10 (as amended) and 4-11

Table 4-4
NET AMOUNT OF AVOIDED EMISSIONS 1995-1999,
USING GFCC AND CFB TECHNOLOGIES AT TAUNTON ENERGY CENTER

	GFCC[1]	CFB (coal-fired)
SO_2	2429 tpy	2454 tpy
NO_2	1504 tpy	1435 tpy
Particulate	122 tpy	178 tpy
CO	143 tpy	<733 tpy>
VOC	15 tpy	<5 tpy>[2]

Source: Taunton Energy Center, EFSC Petition, Tables 4-10 (as amended) and 4-11

[1]Includes limited operation with #2 fuel oil

[2]Indicates a net increase in emissions for this pollutant

alternatives, GFCC technology is considered to be the environmentally preferred alternative. However, because the TMLP RFP restricts the use of fuel technologies to coal, these environmental benefits cannot be achieved by this project, given their stated purpose and need and the objectives of the project proponent. Use of GFCC technology by Silver City Energy LP would likely require a new site, and re-negotiation of power sales agreements, outside the TMLP RFP process.

BACT Analysis

In order to evaluate alternative pollution control systems for the project, a project proponent is required to conduct a Best Available Control Technology (BACT) analysis for all new sources of pollutants that are subject to Federal Prevention of Significant Deterioration (PSD) regulations. The State of Massachusetts also requires BACT for all new or modified sources of emissions subject to state air plans approval.

The BACT Analysis is conducted in a "top-down" fashion, i.e. beginning with the most stringent level of control. It is conducted for each criteria pollutant or group of pollutants. The proponent's BACT analysis resulted in the following proposed control technologies for the project (TEC, 1991c):

> **Nitrogen Oxides (NO_x):** Use of a Circulating Fluidized Bed (CFB) for coal combustion, which inherently promotes efficient combustion at lower temperatures, and Selective Non-Catalytic Reduction (SNCR), involving injection of ammonia and urea to the flue gas stream; emissions reduced to 0.15 lb/MMBtu
>
> **Sulfur Dioxides (SO_2):** Limestone injection into the CFB, and use of medium sulfur coal; emission reduced to 0.256 lb/MMBtu
>
> **Particulate Matter (PM-10):** Use of a fabric filter; emissions reduced to 0.018 LB/MMBtu
>
> **Carbon Monoxide (CO):** Optimizing combustion control (consistent with NO_x removal requirements); emissions reduced to 0.18 MMBtu
>
> **Non-Methane Hydrocarbons (NMHC):** Optimizing combustion control (consistent with NO_x removal requirements); emissions reduced to 0.007 lb/MMBtu
>
> **Non-Criteria Pollutants:** Limestone injection to the CFB, fabric filter, and optimizing combustion temperatures
>
> **Particulate Matter (from Materials Handling):** enclosure of coal pile and other potential sources of dust from coal, ash

and limestone handling; use of dust collectors for ventilation system

The BACT analysis is consistent with recent similar projects permitted by EPA, including the East Providence Cogeneration Project (a 72-MW coal-fired CFB project), and recent permit applications, such as the Half Moon Cogeneration Project and Energy New Bedford Project (Taunton Energy Center, 1991c).

A project similar to the proposed TEC under EPA Region 1 review proposed an add-on SO_2 removal system consisting of a circulating fluidized bed dry scrubber to achieve lower SO_2 emission rates. However, a review of the applicability of such a system for the TEC operating conditions raised serious questions as to its technical feasibility in this situation. The project proponent's analysis concluded, and EPA concurs, that this technology should not be considered BACT for this application given the estimated removal cost of approximately $4,000/ton, an expected increase in ground level concentrations of all the other criteria and non-criteria pollutants due to a reduced temperature plume, extremely high energy requirements associated with the technology, and the fact that there are no existing systems in use on circulating fluidized bed boilers.

4.3 Water Supply Alternatives

The proximity to available water supplies is an important site selection criterion for any power plant, for both cooling water and process water. As discussed above in Section 4.1, the availability of water supply was used by the proponent as a site screening criteria during their selection process. Alternative water supply sources generally include:

- Surface Water Bodies (river, lake, ocean)
- Groundwater
- Municipal Water supply

As previously stated, the proponent developed this proposal in response to a TMLP RFP which contained a specific requirement that the plant be sited in proximity to the existing TMLP Cleary Flood Plant (Taunton Energy Center, 1991d). This requirement eliminated potentially-suitable coastal locations, and focused the site selection process on use of Taunton River, which is presently used by the Cleary Flood Plant. As part of the EFSC site selection process, the proponent also evaluated the feasibility of another site, the Miles Standish Industrial Park, in comparison to the proposed action. While it was considered feasible to construct a water supply pipeline for the Miles Standish site from the Taunton River, this would have required (1) a six-mile water supply pipeline, and (2) a water discharge pipeline of 3-4 miles returning cooling water and treated process water to the Taunton River.

These pipelines would result in several construction and permanent impacts (including potential direct and indirect wetland disturbance along the TMLP rail spur and other points accessing the river). These potential impacts are eliminated with use of the proposed site.

Groundwater sources were potentially available for use for cooling and process water. However, the volume of groundwater required (assuming use of wet cooling towers) is considerable (approximately 1,600 gpm), requiring a large, dedicated aquifer which can support these consumptive withdrawals without adverse impacts to other users. The consumptive use of groundwater for power plant cooling would require complex analyses of hydrogeologic conditions, and potentially-significant impacts on adjacent users; for these reasons, it is generally not considered a feasible alternative for large volumes of cooling water. Much lower volumes of groundwater supplies could potentially be used for process water only (assuming use of an air-cooled condenser). However, plants using these air-cooled systems have other environmental and operational drawbacks, as discussed in Section 4.4, and are thus generally used only where available surface water supplies (e.g. the Taunton River) are unavailable or insufficient for cooling water purposes.

Municipal water supply systems were not considered feasible for use as cooling water for the proposed facility, due to the high volumes required, which would strain the available capacity of the system, and affect other users. If the proposed plant were to use Taunton city water, the proposed withdrawal of 2.95 mgd would result in an approximate 50 percent increase in the average daily requirements for treated water flows in the municipal system (Taunton Energy Center, 1991b). In fact, city concerns over water supply impacts have prompted the proponent to develop a water consumption plan to restrict municipal water uses to potable water supply and boiler makeup water, at an average rate of 86,400 gallons per day (Taunton Energy Center, 1991b).

In view of the TMLP RFP requirements for facility siting, the fact that no significant environmental impacts are expected to result from the use of Taunton River water for cooling (see Section 6.3), and the issues noted above on other potential sources, EPA has determined that the proponent's proposed use of Taunton River water for cooling purposes is environmentally acceptable and no substantially preferable alternatives exist.

4.4 Cooling System Alternatives

There are a number of alternative cooling systems available for use on power plants of this size and type. The selection of a preferred cooling system for a power plant facility is based upon a number of site-specific and technology-driven factors, including (1) the availability and volume of source water for the cooling system; (2) the proximity of the facility to sensitive noise and visual receptors (e.g. residences, public areas); (3) the size and configuration of the project site, and (4) the economic costs and efficiencies of alternative cooling systems.

There are three generic options which can be used for a cooling system; each has advantages and disadvantages, as shown in Table 4-5. These systems include:

- **Once-Through Cooling:** In this system, water is drawn from the source water body and pumped through a series of tubes in a condenser to cool the steam and take up excess heat. The heated water is then directly discharged back to the source water body.

- **Wet Cooling Towers:** In this system, water is also withdrawn from the source water body, and pumped through a condenser to take up excess heat from the plant's steam cycle. This heated water is then circulated through a cooling tower, allowing direct contact with ambient air for cooling.

- **Air-Cooled Condensers:** This system utilizes air, not water, to cool the steam, eliminating the need for cooling towers. Fans discharge the heated air directly to the atmosphere.

Suitability for Taunton Energy Center

As Table 4-5 indicates, the selection of a cooling system requires a trade-off between water quality impacts (due to withdrawal and discharge of cooling water), noise and visual impacts (resulting from cooling tower siting and operation), and air quality impacts (which will vary with relative plant efficiency, and hence fuel consumption, per unit of power produced).

In the case of the Taunton Energy Center site, the existing Taunton River flows are insufficient to allow for once-through cooling; unacceptable water withdrawal, fisheries impingement, and thermal discharge impacts would likely result from the use of this technology. While the use of air-cooled condensers greatly reduces the quantities of water needed, these systems are the least energy efficient to operate due to turbine back pressure and result in greater relative air quality impacts (as more fuel is used), and potentially higher noise impacts (resulting from operation of the larger fans and associated cooling equipment). As a result of these factors, and their additional capital costs, air-cooled condensers are best suited for use where available water resources are very limited, requiring little or no net consumptive use.

Table 4.5. Suitability of Alternative Cooling Systems for Taunton Energy Center

Type of System	Advantages	Disadvantages	Suitability for Taunton Energy Center
Once Through Cooling	o No consumptive water use o No fogging/icing impacts o Less chemical treatment o Least visual/noise impacts o Lower cost o Higher efficiency (less turbine backpressure) o Lower fuel consumption per MW produced	o Higher thermal discharges to receiving waters o Large quantities of water required o Higher potential for fish entrainment/impingement o Habitat loss/disturbance from outfall/diffuser	o Unsuitable (insufficient flows within Taunton River) o Unacceptable thermal impacts
Wet Cooling Towers	o Limited thermal discharges o Lower water withdrawal and fisheries impacts	o Highest visual impacts (Fogging/Icing) o Less efficient (greater fuel consumption/MW produced) o Higher capital & operating costs o Additional land required	o Suitable for site (preferred alternative)
Air-Cooled Condensers	o No thermal discharges o No water withdrawal and fisheries impacts	o Highest noise impacts o Least efficient o Highest capital & operating costs o Additional land required o Moderate visual impacts	o Suitable for site

The use of a wet cooling tower reduces potential water withdrawal and discharge impacts, as compared to once-through cooling, and also allows for a more efficient plant operation than air-cooled condensers. The revised siting of the wet cooling tower system on the east side of the plant, on the opposite side of the closest residences, has significantly reduced the potential for off-site visual, noise and icing/fogging impacts. Thus, the impacts of the wet cooling tower system are environmentally acceptable. Given the siting constraints for this proposed facility, there are no substantially preferable alternatives to the proposed wet cooling tower system for reduction of overall environmental impact.

4.5 Fuel Supply/Storage/Delivery Alternatives

As indicated previously in Section 4.2, the project proponent was specifically directed within the RFP issued by TMLP to utilize coal-combustion technology for their proposed facility; all other technologies would not be considered responsive to the RFP (Taunton Energy Center, 1991b). Thus, while some potential environmental benefits could have been realized through the use of other fuels such as the natural gas (the gas-fired combined cycle technology is discussed and evaluated in Section 4.2), this and other alternatives were not available to the proponent, and thus are not considered feasible alternatives for the proposed action.

The proposed fuel storage and handling system (which includes a fully enclosed structure with concrete floor) is considered to be an environmentally acceptable alternative for coal storage. All major coal transfer points will be equipped with dust pick-up hoods and plenums ducted to fabric filter dust collectors in order to minimize fugitive emissions (Taunton Energy Center, 1991c). Thus, given the restrictive RFP requirements to which the applicant was responding, there are no substantially preferable fuels and storage alternatives to the proposed action.

4.6 No Build Alternative

If the proposed project were not built, the minor increments predicted in noise levels, traffic volume, and water and air discharges would not occur. However, if additional electrical generating capacity is determined to be needed by the state (as discussed above in Section 3.0 "Project Purpose and Need"), it is reasonable to assume that some other facility, with its associated environmental impacts, would be built to fill that need. This assumption is especially reasonable given the fact that EPA is aware of many current proposals for utility and non-utility generator power production facilities in the region.

In evaluating the no action alternative, EPA has considered the issue of conservation and demand side management. After careful review of this issue, we have concluded that DSM/conservation cannot truly be part of the no build alternative to the TEC facility for consideration by this agency. Although EPA supports federal and state energy policy incorporating increased efforts in DSM programs, EPA has no authority to require DSM and the prevalence of DSM will not be affected one way or the other by EPA's decision on issuance of the NPDES permit for the proposed Taunton Energy Center. Silver City Energy LP would not itself embark on DSM programs if it does not build the proposed facility. Similarly, EPA cannot require anyone to implement DSM measures in place of the TEC facility. Furthermore, if the proposed facility is not built, other proposed facilities might be built in its place.

DSM measures are better thought of as part of the analysis of whether there is an energy need for a particular power generating facility rather than as part of the no build alternative. As was noted in the "Project Purpose and Need" discussion above, under Massachusetts IRM regulations, the evaluation of a utility's resource needs includes, by statute, an examination of all DSM technical potential in the utility's service territory. This includes examination of conservation, load management, and fuel switching technologies, measures, and actions. Hence, state energy regulators, who have the authority to require DSM options when evaluating resource needs of utilities, do require that DSM measures be considered in determining whether there is a need for new generating facilities such as TEC.

5.0 AFFECTED ENVIRONMENT

The following sections present information on the natural and social resources that could be potentially affected by the proposed project.

5.1 Land Use

The site for the proposed Taunton Energy Center is located approximately three miles south of Taunton Center on a 100 acre parcel of land owned by the Taunton Municipal Lighting Plant (TMLP). The TMLP parcel presently houses the Cleary Flood Station which occupies about 20 acres in the northeast portion of the site. The TEC will be located south and west of the existing power station on land leased from TMLP. The cooling tower will be located east of the railroad and south of the existing power station in an area that is predominantly open grassland. The power block, fuel storage building, and associated equipment will be constructed west of the railroad siting. This 25 acre area is presently undeveloped and was previously used for a gravel removal operation.

The areas surrounding the TMLP parcel are primarily residential with some large areas of undeveloped land. Medium density residential development is located along the length of Railroad Avenue to the south of the site and Route 138 to the west. The majority of the properties on Route 138 abut the TMLP property line but are screened from the site by a ridge that runs from north to south between Route 138 and the project site. There are three houses on the north side of Railroad Avenue that abut the TMLP property, however, the majority of the residential development on Railroad Avenue is located on the south side of the street.

The area to the east of the site across the Taunton River is undeveloped. The nearest residences are located on Berkley Street, approximately 2,500 feet to the east. Much of the undeveloped land to the east is swampy in nature and is occupied by pipeline and electric easements. Directly north of the site is the Blake Cemetery which lies between the existing railroad siding and the Taunton River. The nearest developed area lies about 1,400 feet north of the existing site drive on Boylston Street. The area between the site and Boylston Street is undeveloped and is a combination of woods and open fields.

5.2 Site Drainage and Stormwater Flows

The entire 100 acre TMLP land parcel, including the plant site area, is part of the Taunton River watershed basin. The site generally drains to the east towards the Taunton River. Runoff from areas west of the existing railroad drains to a small wetland at the old gravel pit site. Areas east of the railroad drain overland to the discharge canal which conveys discharges from the existing TMLP facility the Taunton River.

5.3 Taunton River

The project site is located on the Lower Taunton River between the Mill River and Three Mile River.

5.3.1 Taunton River Flows

The river at the project site is channel-like in appearance, although still tidal with a mean range of four to five feet. The width of the river by the site is approximately 100 to 150 feet at mean low water. The 7Q10 low flow (exceeded by 90% of the yearly minimum seven day average flows) for the Taunton River at the site is approximately 51 cubic feet per second (cfs). The proposed project will withdraw 3.9 cfs from the Taunton River and discharge approximately 0.8 cfs back into it. The difference will be lost to evaporation in the cooling towers.

5.3.2 Taunton River Water Quality

The Massachusetts DEP Division of Water Pollution Control performed a survey of water quality in the Taunton River Basin during the summer of 1986 (Taunton Energy Center, 1991b). Samples were taken above the Taunton Municipal Wastewater Treatment Plant (WWTP), below the Taunton WWTP, below TMLP on the west river bank at the bend, and at the Berkley Bridge. Additional water quality samples were collected in December 1990 at the intake of the existing TMLP facility.

Data from both the 1986 survey and the 1990 samples (Taunton Energy Center, 1991b) indicate that the Taunton River in the vicinity of the project site meets Class SB standards.

5.3.3 Taunton River Biology

Fisheries Resources

The Taunton River is historically described as having a significant anadromous fishery resource of alewife (*Alosa pseudoharengus*). Anadromous fish are species that live in marine waters, but return to specific freshwater bodies to spawn. The Taunton River is also known to have populations of the anadromous rainbow smelt (*Osmerus mordax*). The lower reaches of the Taunton River and as far upstream as the Wastewater Treatment Plant in the City of Taunton have been identified as an anadromous fish run in the 1977 *Massachusetts Coastal Zone Management Atlas*.

The Division of Marine Fisheries and Wildlife (DMFW) conducted sampling programs at several locations upstream and downstream of the project site during 1955, 1975, and 1990 (Taunton Energy Center, 1991b). There were no sampling efforts in the immediate project site area during these studies. Stations sampled in 1975 were approximately three, five, and seven miles upstream from the project site. Table 5-1 lists the 18 species of fish collected.

The fish collected were mainly freshwater species, with some anadromous and catadromous species. Stations sampled in 1955 and 1990 were downstream of the project site in an area subject to increases in salinity during times of low river flow. Fish collected during these sampling events are listed on Table 5-2 and include freshwater, marine, anadromous, and catadromous species.

The U.S. Fish & Wildlife Service recently completed a sturgeon study in the Taunton River. The purpose of the study was to determine occurrence of shortnose sturgeon (*Acipenser bevirostrum*) and Atlantic sturgeon (*Acipenser oxyrhynchus*) in the Taunton River. The impetus for these studies was a 1905 report of juvenile Atlantic sturgeon in the Taunton River (Tracy, 1905) H.C., "A List

TABLE 5-1
FISH SPECIES COLLECTED IN THE
UPPER TAUNTON RIVER UPSTREAM OF
THE PROJECT SITE
(Madore, 1976; Hurley, 1990)

COMMON NAME	SCIENTIFIC NAME
ANGUILLIDAE - Freshwater Eels	
American Eel	Anguilla rostrata
CLUPEIDAE - Herring	
Alewife	Alosa pseudoharengus
ESOCIDAE - Pikes	
Redfin Pickerel	Esox americanus
Chain Pickerel	Esox niger
CYPRINIDAE - Carps and Minnows	
Carp	Cyprinus carpio
Golden Shiner	Notemigonus crysoleucas
Common Shiner	Notropis cornutus
Fallfish	Semotilis corporalis
CATOSTOMIDAE - Suckers	
White Sucker	Catostomus commersoni
Creek Chubsucker	Erimyzon oblongus
ICTALURIDAE - Freshwater Catfish	
Brown Bullhead	Ictalurus nebulosus
PERCICHTHYIDAE - Temperate Basses	
White Perch .	Morone americana

- Continued -

TABLE 5-1 (Continued)
FISH SPECIES COLLECTED IN THE
UPPER TAUNTON RIVER UPSTREAM OF
THE PROJECT SITE
(Madore, 1976; Hurley, 1990)

COMMON NAME	SCIENTIFIC NAME
CENTRARCHIDAE - Sunfish	
Pumpkinseed	*Lepomis gibbosus*
Bluegill	*Lepomis macrochirus*
Largemouth Bass	*Micropterus salmoides*
Black Crappie	*Pomoxis nigromaculatus*
PERCIDAE - Perch	
Tesselated Darter	*Etheostoma olmstedi*
Yellow Perch	*Perca flavescens*

Sour... Taunton Energy Center, 1991b. Draft Environmental Impact Report for the Taunton Energy Center Prepared by HMM Associates, February, 1991. Concord, MA.

TABLE 5-2
FISH SPECIES COLLECTED IN THE
UPPER TAUNTON RIVER DOWNSTREAM OF
THE PROJECT SITE
(Bridges, 1956?; Madore, 1975)

COMMON NAME	SCIENTIFIC NAME
ANGUILLIDAE - Freshwater Eels	
American Eel	Anguilla rostrata
CLUPEIDAE - Herring	
Alewife	Alosa pseudoharengus
Atlantic Menhaden	Brevoortia tyrannus
CATOSTOMIDAE - Suckers	
White Sucker	Catostomus commersoni
PERCICHTHYIDAE - Temperate Basses	
White Perch	Morone americana
CENTRARCHIDAE - Sunfish	
Largemouth Bass	Micropterus salmoides
CYPRINODONTIDAE - Killifish	
Common Mummichog	Fundulus heteroclitus
Striped Killifish	F. majalis
ATHERINIDAE - Silversides	
[illegible]antic Silverside	Menidia menidia
POMATOMIDAE - Bluefish	
Bluefish	Pomatomus saltatrix
SOLEIDAE	
Hogchoker	Trinectes maculatus

Source: Taunton Energy Center, 1991b. Draft Environmental Impact Report for the Taunton Energy Center. Prepared by HMM Associates, February, 1991. Concord, MA.

of Fishes of Rhode Island," *36th Annual Report of the Commission on Inland Fisheries, Providence*).

An in-river fisheries sampling program was initiated by the project proponent on November 28, 1990. Sampling included ichthyoplankton, gill net, fyke net, beach seine, and benthic sampling. Ichthyoplankton collections taken in November and December contained no fish eggs or larvae. Nineteen fish or five species (chain pickerel, banded killifish, fourspine stickleback, bluegill, and tesselated darter) were collected from November to January, 1991. Macroinvertebrate sampling was conducted in November, 1990 at three locations extending across the river from the mouth of the discharge channel to the opposite shore. The locations included one near-shore location, one mid-channel location, and one far-shore location. Sediment grain size analysis indicated that the river sediments in the area sampled are generally sandy with some silt present near-shore. The November sampling did not contain any benthic macroinvertebrates, though this may have been a function of the sampling procedure (a 2 mm mesh sieve was used). A similar sampling in December using a 0.5 mm mesh revealed the presence of midge, larvae, oligochaetes, and bivalves in one sample (TEC, 1991b).

5.4 Wetlands and Floodplain Resources

5.4.1 Wetlands Resources

Eight wetland areas have been identified on or adjacent to the TMLP site. Wetlands comprise approximately 25 percent of the 100 acre TMLP site (see Figure 5-1). The following is a more detailed discussion of each of these wetland areas (Taunton Energy Center, 1991f).

Wetland 1. Wetland 1 is a large bordering vegetated wetland located east of the existing rail siding bordering the Taunton River. It is classified as a scrub/shrub riverine wetland. This wetland also contains marsh bordering the discharge canal. Vegetation along the edge of the wetland includes red maple (*Acer rubrum*), speckled alder (*Alnus rugosa*), northern arrowwood (*Viburnum recognitum*), jewelweed (*Impatiens capensis*), sensitive fern (*Onoclea sensibilis*), and skunk cabbage (*Symplocarpus foetidus*). This wetland is located entirely within the 100-year floodplain of the Taunton River. Soils underlying this wetland are mucky peat. These soils are very poorly drained and are typically associated with tidal waters such as the Taunton River. The 100-foot buffer zone of Wetland 1 shows evidence of previous clearing for TMLP facilities. The forested area adjacent to the wetland extends generally less than 50 feet from the wetland edge.

Wetland 2. Wetland 2 is a wet meadow (bordering vegetated wetland) located adjacent to and south of the entrance road to the existing

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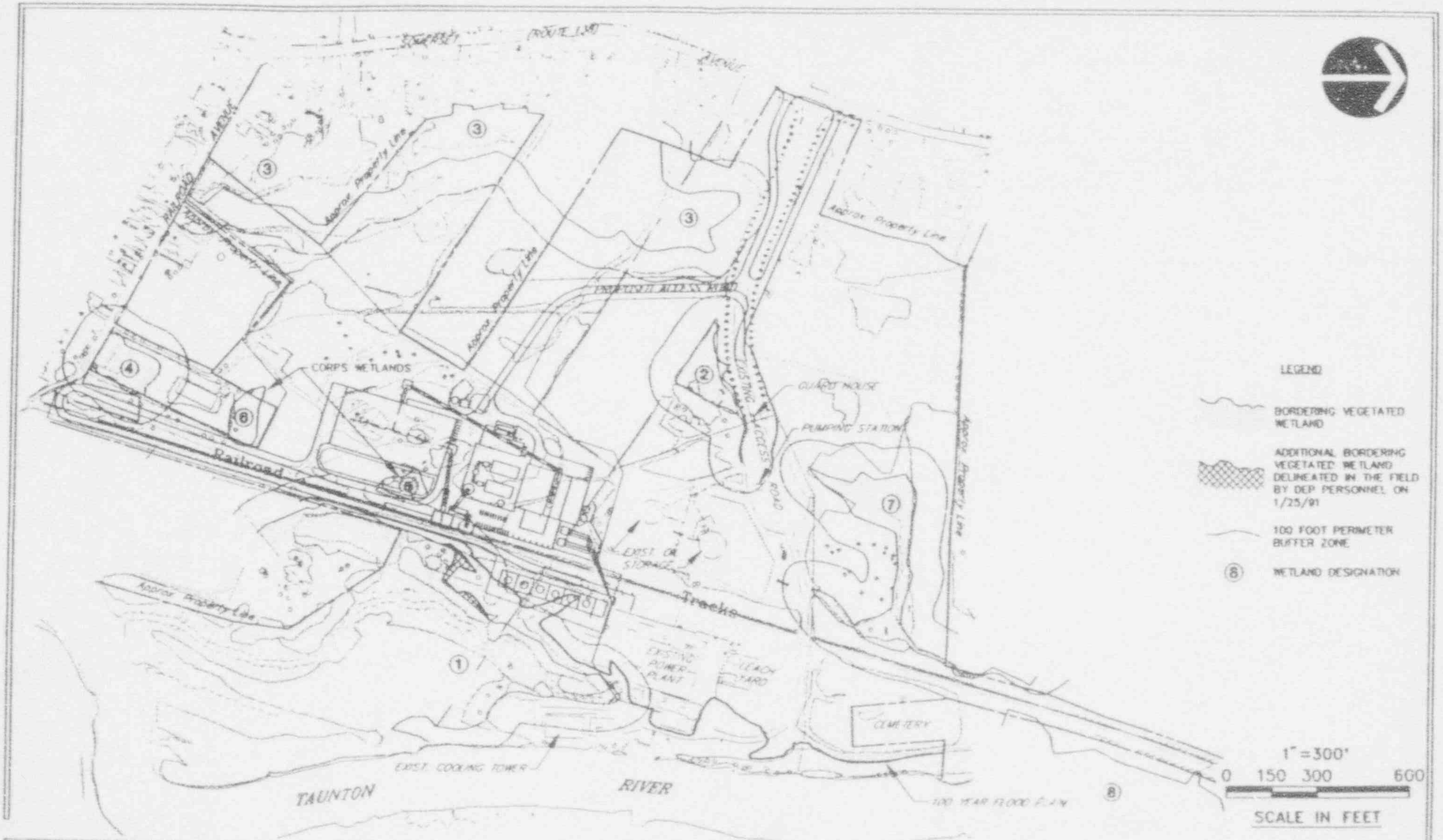


PLAN OF WETLAND
TAUNTON ENERGY CENTER

Figure 5-1

facility. It is classified as a non-persistent emergent riverine wetland. The wetland area is an abandoned agricultural field and shows evidence of apparent soil disturbance and clearing. A maintained Shell Oil gas pipeline bisects the wetland. Common vegetation occurring in the meadow is dominated by goldenrod (*Solidago* spp.), soft rush (*Juncus effusus*), jewelweed (*Impatiens capensis*), deer tongue (*Panicum clandestium*), and sensitive fern (*Onoclea sensibilis*). Vegetation in this meadow also includes a number of upland species but soils are indicative of hydric conditions. The wetland is drained by a small intermittent channel which flows east into the parking area. The channel also drains storm water run-off from the surrounding parking areas.

Wetland 3. Wetland 3 is a bordering vegetated wetland along the western portion of the property. It is classified as a scrub/shrub riverine wetland. The wetland includes a perennial stream which originates in the wetland, flows south and is culverted under Railroad Avenue. Vegetation in this area includes red maple (*Acer rubrum*), tupelo (*Nyssa sylvatica*), American elm (*Ulmus americana*), Northern arrowwood (*Viburnum recognitum*), and sweet pepperbush (*Clethra alnifolia*). Soils in this area are Ridgebury extremely stony fine sandy loam. These soils are generally poorly drained with a seasonally high water table. Hydrologic indicators in the interior of this wetland such as surface inundation and saturated soils suggest a seasonally flooded water regime.

Wetland 4. Wetland 4 is a bordering vegetated wetland located mainly off the property bordering the northern edge of railroad Avenue. it is classified as a forested and scrub/shrub wetland. This area is dominated by woody vegetation and is associated with a series of drainage ditches. There is a large amount of refuse and discarded trash in this wetland. Species occurring in this wetland include red maple (*Acer rubrum*), American elm (*Ulmus americana*), black cherry (*Prunus serotino*), and northern arrowwood (*Viburnum recognitum*). Soils within the area are inundated and ponded. Surface drainage is culverted under Railroad Avenue and flows off the property.

Wetland 5. Wetland 5 is a small isolated manmade depression located approximately 1,050 feet north of Railroad Avenue along the west side of the rail siding in the area disturbed by previous gravel operations. This wetland does not meet the legal definition of a wetland according to the Massachusetts Wetland Protection Act. However, it does satisfy the technical criteria necessary for federal wetland jurisdiction (hydrophytic vegetation, hydric soils, hydrology). The edge of this depression is confined by scattered boulders and dominated by upland vegetation. Surface water depth within this depression ranges between 4 and 24 inches. A band of wetland vegetation, dominated by meadow emergents, is contiguous with the depression. Evidence of trash dumping occurs throughout the depression. This wetland is classified as emergent and open water palustrine.

Wetland 6. Wetland 6 is found primarily off the property in the southeast corner of the site. This area has apparently been influenced by past agricultural activities as evidenced by tilled soils. Vegetation is comprised of both wetland and upland emergents. Soils underlying this wetland are characteristic of prolonged saturated conditions. This area does not meet the Massachusetts regulatory conditions of a wetland; however, it does fall under the regulatory jurisdiction of the Army Corps of Engineers. It is classified as a riverine emergent wetland.

Wetland 7. Wetland 7 is a wet meadow/swamp (bordering vegetated wetland) in the extreme northeast corner of the property. Vegetation within the wetland include common reed (*Phragmites australis*), joe-pye-weed (*Eupatorium* sp.), northern arrowwood (*Viburnum recognitum*), silky dogwood (*Cornus amomum*), and sensitive fern (*Onoclea sensibilis*). Soils and hydrology show evidence of historic disturbance. Surface flow within the wetland originates from stormwater runoff from adjacent impervious surfaces. Surface water is channelized through a drainage ditch which flows north paralleling the western edge of the rail siding. This wetland is classified as an emergent and shrub/scrub riverine wetland.

Wetland 8. Wetland 8 is a shrub swamp/marsh (bordering vegetated wetland) along the eastern edge of the railroad right-of-way. Most of this wetland is located under an existing overhead transmission line and therefore subject to regular maintenance practices. Vegetation in this wetland is dominated by shrubs such as northern arrowwood (*Viburnum recognitum*), highbush blueberry (*Vaccinium corymbosum*) and red-osier dogwood (*Cornus stonifera*). Emergent species include blue flag (*Iris versicolor*), cinnamon fern (*Osmunda cinnomonea*) and jewelweed (*Impatiens capensis*). The water regime in this wetland is affected by surface flooding from the Taunton River. Soils are characterized as Westbrook mucky peat. This soil type is an organic soil typically subject to tidal inundation. This wetland is classified as a scrub/shrub emergent wetland.

5.4.2 Floodplain Resources

The 100-year floodplain at the site is associated with the lateral extent of flooding associated with the Taunton River. According to the Federal Emergency Management Agency (FEMA), the 100-year flood elevation is 14 feet above the boundary of the floodplain. The floodplain is located east of the railroad bed and encompasses approximately 20 acres of the site (see Figure 5-1). Additional floodplain corresponds to Wetland 1 and its adjacent buffer zone (Taunton Energy Center, 1991f).

5.5 Tidelands and the Coastal Zone

The Taunton Energy Center will be located primarily on uplands, away from the Taunton River. It will be located adjacent to, but not within, the Massachusetts Coastal Zone as represented in the 1977 *Massachusetts Coastal Zone Management Atlas*. Only those components of the plant related to intake and discharge of water from the Taunton River will be located within or adjacent to tideland resources (Taunton Energy Center, 1991b).

The mean tidal range of the Taunton River in the vicinity of the project site is 2.8 feet. Several existing structures associated with the TMLP are located in or adjacent to tidelands at the site. These include an intake channel and associated riprap, a pump house, a discharge structure, and a discharge canal. It does not appear that a Chapter 91 Waterways license was issued for the construction of the existing discharge canal or outfall structure. The activity took place above the Historic High Water Mark of the Taunton River, landward of the Chapter 91 jurisdiction at the time of construction.

5.6 Rare and Endangered Species

According to the Massachusetts Natural Heritage and Endangered Species Program, the project site does not provide habitat for wetland species considered endangered or threatened; however, an area approximately 1.4 miles downstream of the site in the Taunton River and adjacent wetlands have been identified by the Massachusetts Natural Heritage and Endangered Species Program as habitat for the Northern diamondback terrapin (*Malaclemys terrapin*), a threatened species. In a letter dated March 14, 1989, the Massachusetts Natural Heritage and Endangered Species Program identified this area as habitat for the Northern diamondback terrapin (*Malaclemys terrapin*), a threatened species (Taunton Energy Center, 1991b). The northern diamondback terrapin can be found in coastal marshes, tidal flats, coves, estuaries, inner edges of barrier beaches, or any sheltered body of salt or brackish water. The lower Taunton River and its associated marsh systems are an estuarine habitat suitable to the terrapin.

The U.S. Fish & Wildlife Service conducted sturgeon studies in the Taunton River from May to October, 1991 and again from May to July, 1992 to determine whether either Atlantic sturgeon (*Acipenser oxyrhynchus*) or shortnose sturgeon (*Acipenser bevirostrum*) currently use or breed in the Taunton River (Kynard, pers. comm., 1992). The impetus for those studies arose out of a single 1905 report of a juvenile Atlantic Sturgeon in the Taunton River. The Atlantic sturgeon is currently listed as a state endangered species and the shortnose sturgeon is a federally endangered species.

5.7 Visual Resources

The Taunton River, a quiet, slow-moving stream, is bordered by wooded wetlands and agricultural areas. Immediately to the west of the project site, however, views are dominated by the Unit 9 cooling tower and the existing TMLP facility.

5.8 Recreational Resources

Boating access to the Taunton River in the immediate plant vicinity is limited. The nearest boat yard is located nearly five miles down river from the project site. However, the Appalachian Mountain Club and the Taunton River Watershed Alliance have identified canoe launching points, and sponsored joint canoe floats on several occasions along the main stem of the Taunton River (TRWA, 1991). The bulk of observed recreational boating in the project vicinity is generally limited to canoes, kayaks, and other small craft.

5.9 Historic and Archaeological Resources

The proponent notes that the *Massachusetts Register of Historic Places, 1989* identifies only one historic property within a mile of the project site (Taunton Energy Center, 1991b). The Peter Walker House, located at 1679 Somerset Avenue, lies approximately one-half mile south of the project site near the city boundary. In addition, the Blake Cemetery is located immediately north of the existing TMLP facility.

Although the historic character of the project area was agricultural prior to industrialization, few remnants of that activity remain in the project vicinity, though agricultural fields are evident in Berkley across the River. The project site, prior to being excavated for gravel and fill, was a small working farm, and the deep, narrow lots fronting on Somerset Avenue served as wood lots for firewood for heating and cooking.

5.10 Traffic

In order to assess existing traffic conditions in the vicinity of the access drive to the proposed facility (shown in Figure 5-2), traffic counts were conducted at the intersection of Somerset Avenue (Route 138) and the TMLP driveway.

Somerset Avenue is a state numbered route (Route 138) that provides northerly/southerly oriented access between Taunton to the north and Somerset and Fall River to the south. Route 138 is under state jurisdiction opposite the TMLP driveway. Interstate 495 is located north of Taunton and can be accessed via Route 138 in Raynham.

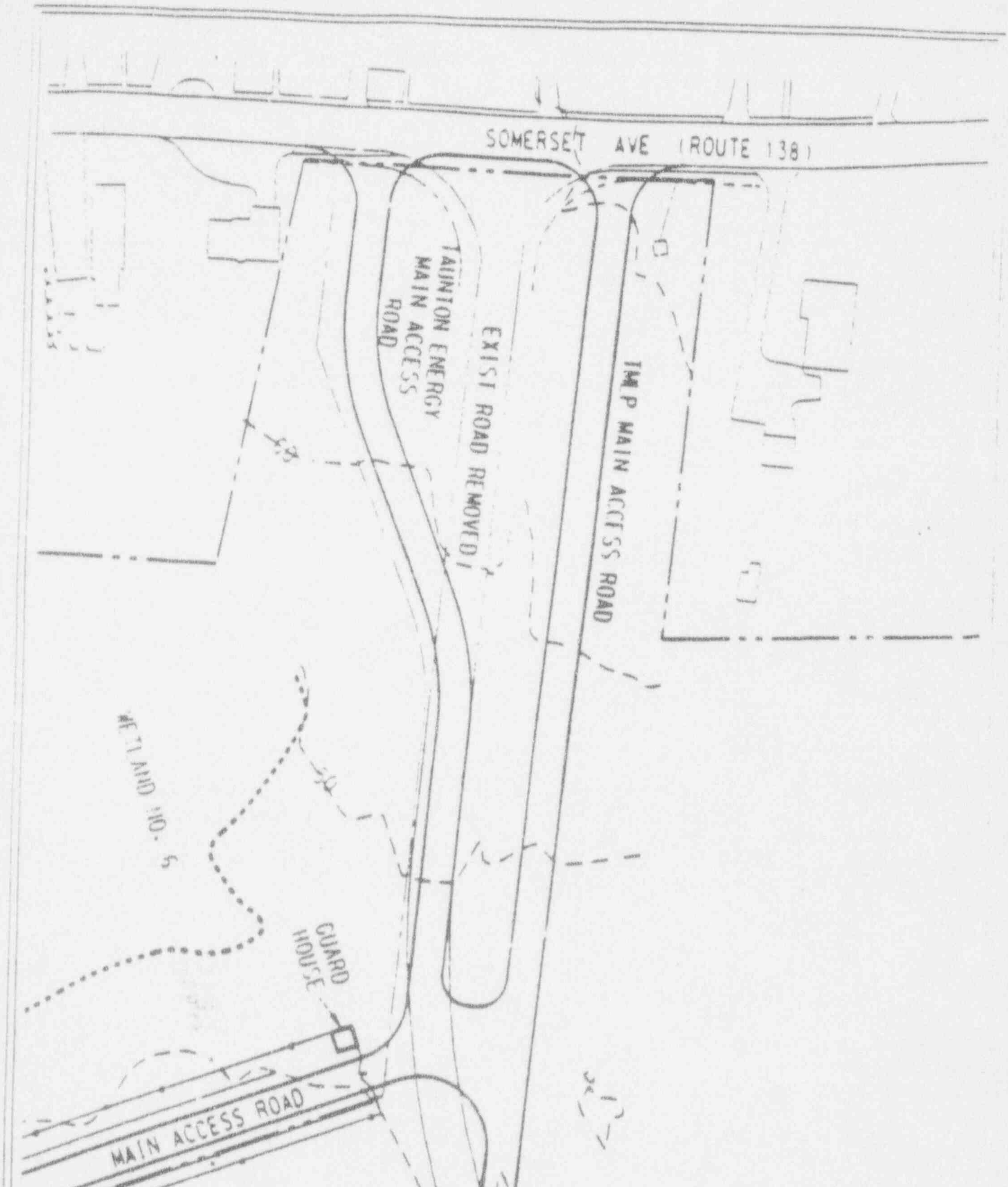


Figure 5-2

PROPOSED SITE ACCESS DRIVE

Source: Taunton Energy Center, 1991b. Draft Environmental Impact Report for the Taunton Energy Center. Prepared by HMM Associates, February, 1991. Concord, MA.

The TMLP driveway has a total pavement width of approximately 36 feet with 3-foot paved shoulders. A stop line is present on the TMLP driveway approach. The intersection of Somerset Avenue and the TMLP driveway is a "T"-intersection with traffic control provided by a STOP sign. At this location, Somerset Avenue has a total pavement width of approximately 30 feet. This allows for a single travel lane in each direction of approximately 12 feet in width. A paved shoulder of three feet exists on each side of the roadway. The posted speed limit on Somerset Avenue is 40 miles per hour (MPH), with an observed speed of approximately 45 MPH. The grade on Somerset Avenue at the TMLP driveway is approximately level. Stopping sight distances were measured to be over 450 feet to the south and 380 feet to the north. These distances are adequate for the observed speed and grade when compared with a standard requirement of 375 to 400 feet.

Weekday manual turning movement counts were conducted in November, 1990 between the hours of 7:00 AM and 9:00 AM and 4:00 PM and 6:00 PM. In addition, automatic traffic recorders (ATRs) were installed on Somerset Avenue and on the TMLP driveway, which provided weekday, Saturday, and Sunday 24-hour traffic volume data.

Traffic conditions at the Somerset Avenue/TMLP driveway intersection were examined during the AM and PM weekday peak commuter hours for the following conditions:

- 1990 Existing
- 1993 Construction year, no-build
- 1995 Operations year, no-build
- 1993 Construction year, build
- 1995 Operations year build

Existing Traffic Volumes

A total of 6,466 vehicles were counted on Somerset Avenue south of the TMLP driveway during a typical 24-hour weekday period. On a Saturday, a total of 6,513 vehicles were counted, while 5,606 were counted on a Sunday. These are the actual counts and have not been adjusted for seasonal variations.

The morning weekday peak hour was from 7:15 to 8:15 AM and the evening peak hour occurred from 4:30 to 5:30 PM. These traffic counts have been adjusted to reflect peak month of the year conditions based on continuous traffic count data from Massachusetts Department of Public Works Count Station No. 3 on Route 44, east of Route 118 in Rehoboth.

Existing Traffic Operations

Using adjusted AM and PM traffic volumes, the level of service at the intersection was calculated. Level of Service (LOS) refers to the quality of traffic flow along roadways and at intersections. At signalized intersections, LOS is defined in terms of average approach delay in seconds per vehicle. The LOS worsens as the average delay increases. It is described in terms of LOS A through F; where A represents the best possible conditions and F represents forced-flow, or failing conditions. During AM peak hour, the intersection was found to operate at LOS A. In the PM peak hour LOS B operations were calculated.

5.11 Rail

The site is bisected by a railroad siding running north to south. Coal will be transported to the Taunton Energy Center on an existing 3.1 mile rail spur to be reconstructed by Conrail. The rail spur is owned by TMLP which will lease it to the TEC.

5.12 Air Quality

Background levels of the air pollutants nitrogen dioxide (NO_2), sulfur dioxide (SO_2), total suspended particulates (TSP), and ozone (O_3) in the project area are summarized in the Draft Environmental Impact Report (Taunton Energy Center, 1991b) based on: existing monitoring data from the Southeastern Massachusetts Air Quality Control Region (Taunton Energy Center, 1991c), several private monitoring sites used in the State's annual reports (Taunton Energy Center, 1991c), and Massachusetts DEP guidance (Massachusetts DEP, 1987). Monitoring data and background levels are presented in Table 5-3.

There are no data available for fine particulate matter (PM-10) or carbon monoxide (CO) in the Southeastern Massachusetts Air Quality Control Region. PM-10 background levels were conservatively assumed to be equivalent to TSP ambient concentrations. CO ambient levels are typically elevated in areas of high traffic density and are generally lower in low density traffic areas, such as the project site. The proponent reported no background CO levels within the air plans application, as project CO emissions were below significance levels requiring assessment of background conditions (Taunton Energy Center, 1991c).

An "attainment area" is an area meeting the federal and state ambient air quality standards for a particular air pollutant. A "non-attainment area" is an area violating ambient standards for a particular pollutant. An "unclassified area" is an area for which sufficient data are unavailable to determine attainment or non-attainment status. Taunton is presently designated as an attainment area for NO_2, SO_2, and lead (Pb); and an unclassified area for carbon monoxide (CO) and total suspended particulates (TSP). Taunton is expected to be in attainment of the new fine particulate matter standards (PM-10). The entire state of Massachusetts is designated as a non-attainment area for ozone (O_3).

Table 5-3

CRITERIA POLLUTANT BACKGROUND LEVELS

Pollutant	Averaging Period	1986 Conc. (ug/m3)	1987 Conc. (ug/m3)	1988 Conc. (ug/m3)	Background (ug/m3)	NAAQS (ug/m3)
SO_2	3-Hour	401	359	655	655	1,300
	24-Hour	104	92	89	104	365
	Annual	17	16	18	18	80
NO_2	1-Hour	160 (1984)	122 (1985)	83 (1986)	160	320**
	Annual	28 (1984)	30 (1985)	NA	30	100
O_3*	1-Hour	0.107*	0.124*	0.129*	0.129*	0.12*
TSP***	24-Hour	61	67	57	67	150
	Annual	25	28	26	28	60**

* Concentrations in ppm.
** State guideline.
*** PM-10 levels will be conservatively assumed equal to TSP background concentrations.

Source Taunton Energy Center, 1991c. PSD/Air Plans Application for the Taunton Energy Center. Prepared by HMM Associates, April, 1991. Concord, MA.

5.13 Noise

Significant noise sources in the area of the site include industrial, commercial, and traffic-related sources. Ambient noise level measurements were made at representative community locations background air emissions in the vicinity of the proposed facility (Taunton Energy Center, 1991c). Complete surveys were conducted under winter and late summer conditions during: weekday day,weekday night, weekend day, and weekend night. Several noise measurement locations around the project area were selected to obtain an adequate spatial representation of the noise levels around the proposed site (Figure 5-3). Measurements of ambient noise levels were conducted at each of the noise measurement locations. Weekday measurements were scheduled to correspond to off-peak traffic levels. The existing Taunton Municipal Light Plant (TMLP) plant was not operating during most night measurements. All measurements were made under low wind and no-rain conditions.

The four levels most commonly used to describe ambient noise are defined as follows:

L_{90} - The level exceeded 90 percent of the time, commonly used to describe the residual, or "background" noise level, below which ambient noise levels rarely fall

L_{50} - The level exceeded 50 percent of the time, commonly used to describe the "median" ambient sound level

L_{10} - The level exceeded 10 percent of the time, often used to describe the "near-peak", "common maximum", or "intrusive" sound levels, such as those caused by vehicle passbys

L_{eq} - The level of a steady sound that would produce the same amount of sound energy as the observed fluctuating sound

The results of the summer and winter surveys are summarized on Figures 5-4 and 5-5. The bars represent four sampling periods at each location. Minimum (L_{90}) levels in the communities around the proposed site ranged from 31 dBA to 37 dBA. These were all measured during winter weekend nighttime periods when there were no significant TMLP operations and winds were calm so no appreciable contribution was observed from dry leaves. These values are believed to be representative of the ambient noise levels in the project area.

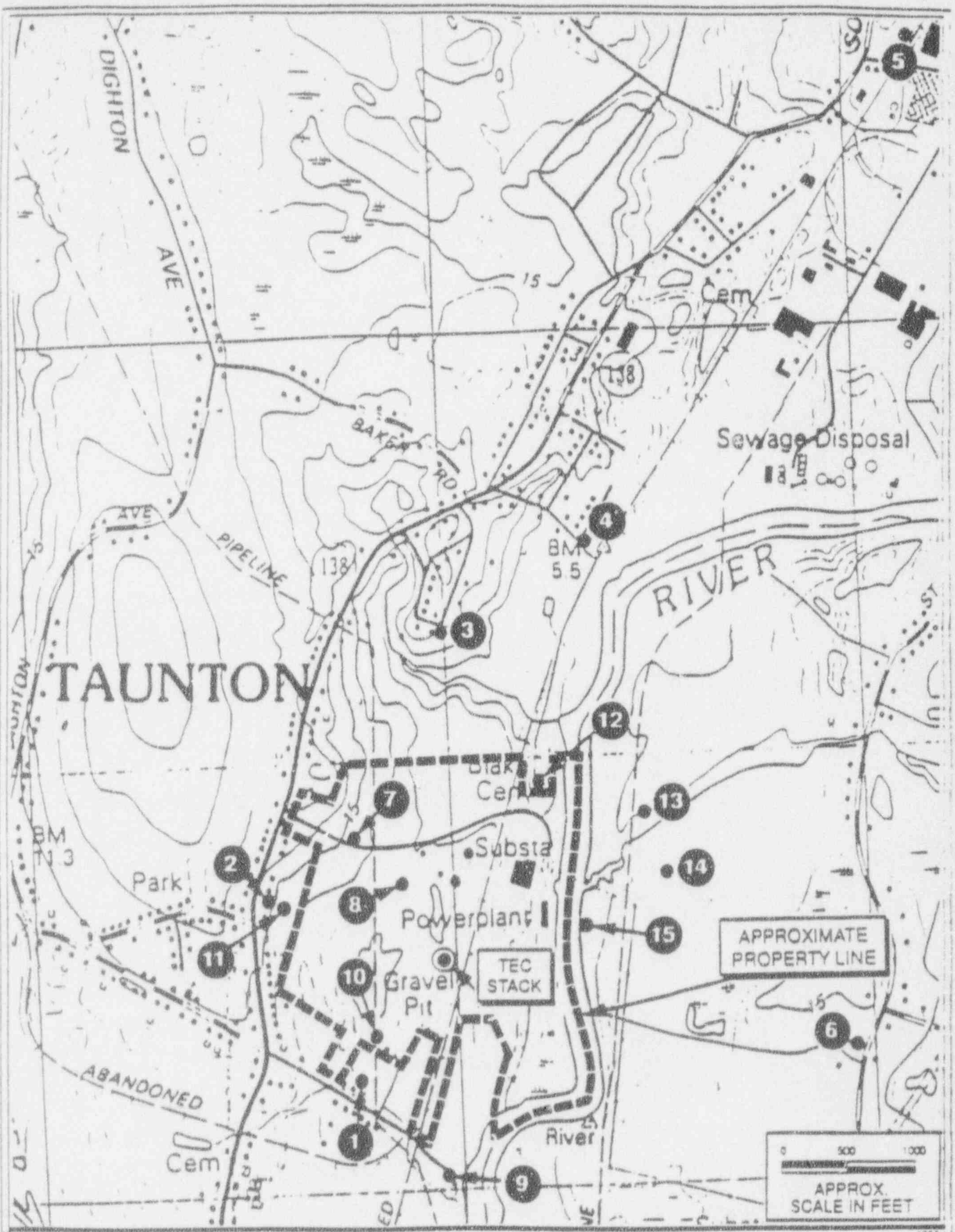
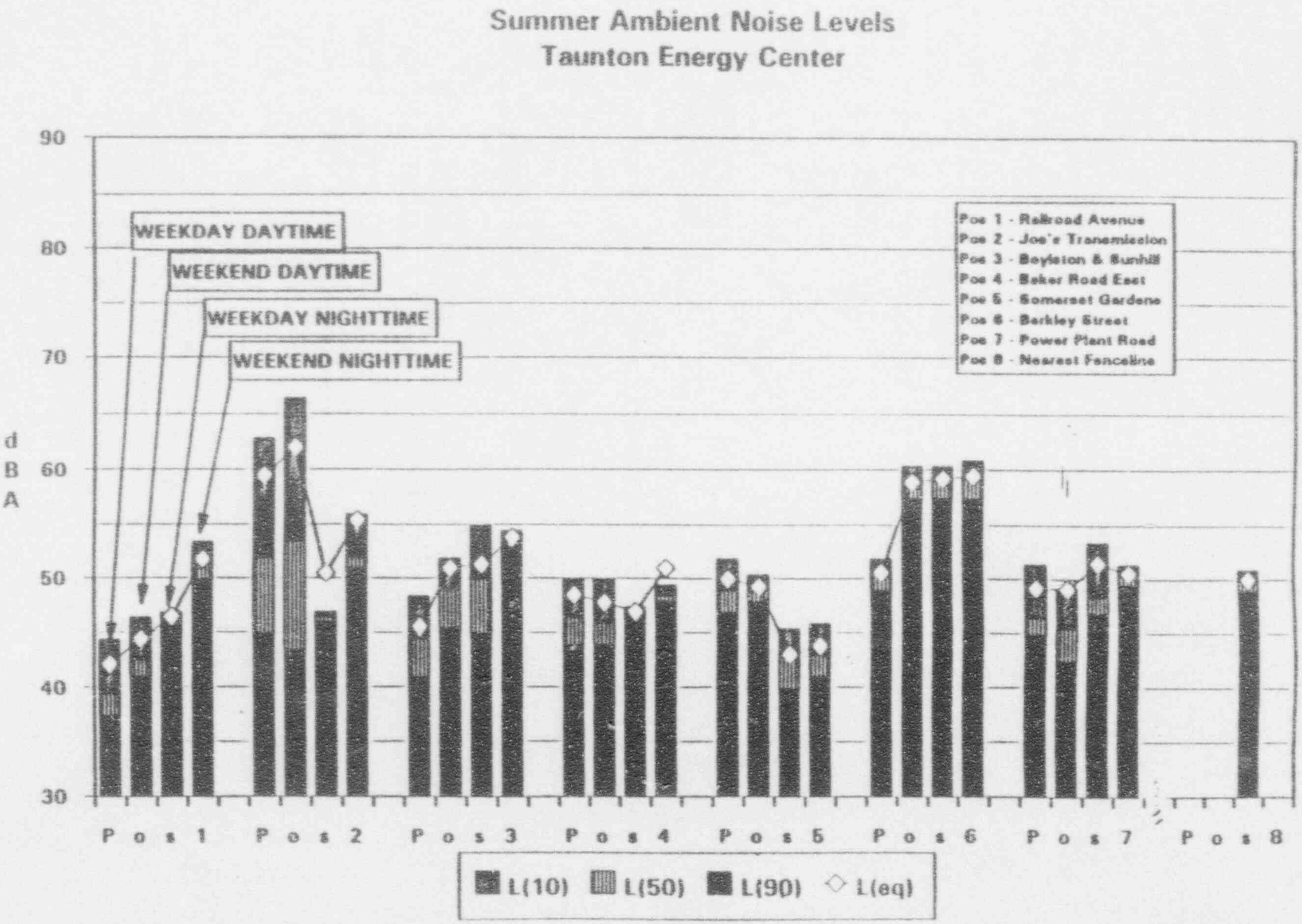


Figure 5-3
TAUNTON ENERGY CENTER SITE AND
NOISE MEASUREMENT LOCATIONS

Source: Taunton Energy Center, 1992a. Major Comprehensive Plans Approval Application. Revised Noise Levels Assessment. Prepared by HMM Associates, January, 1992.

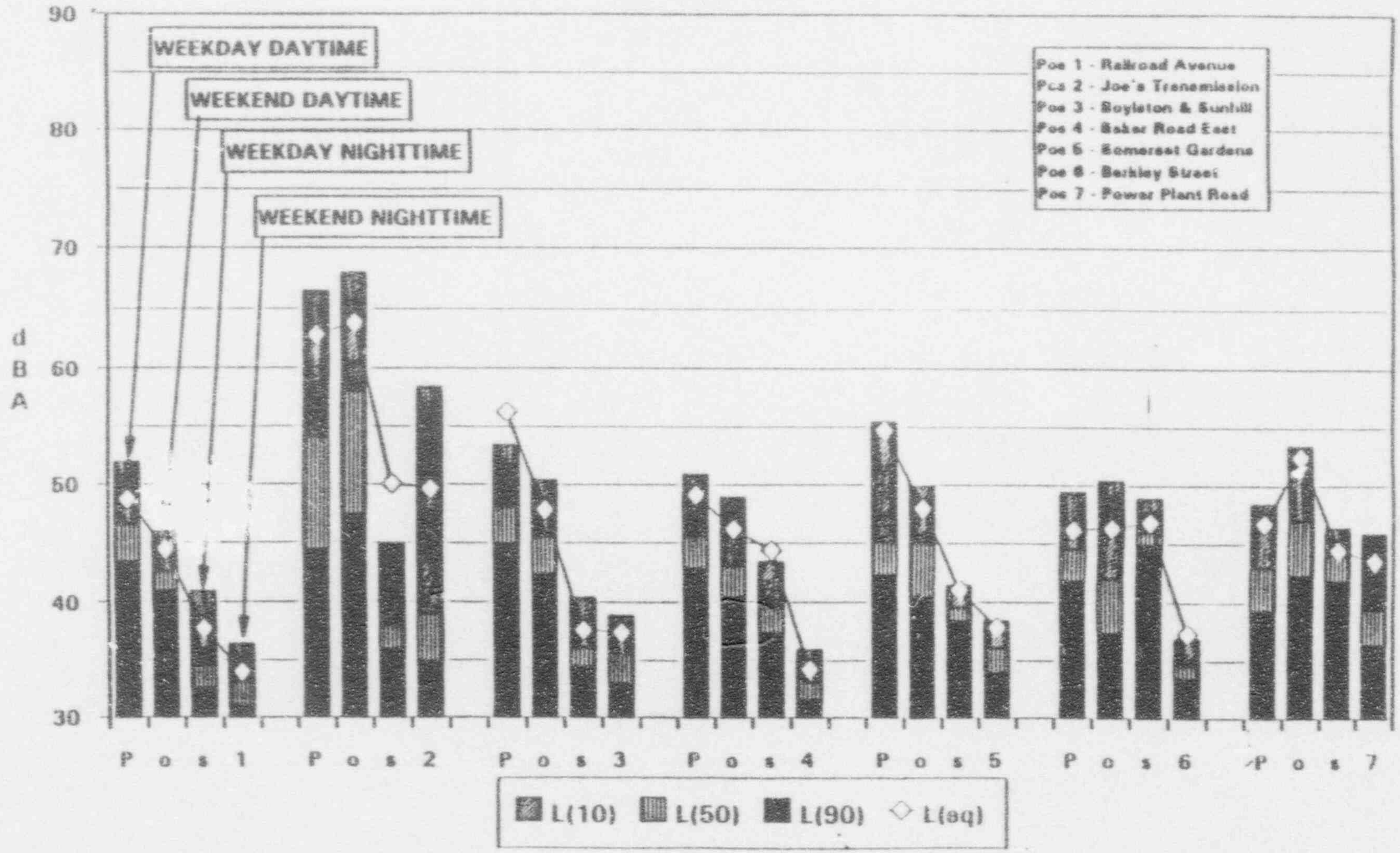
Figure 5-4



Source: Taunton Energy Center, 1992a. Major Comprehensive Plans Approval Application. Revised Noise Levels Assessment. Prepared by HMM Associates, January, 1992.

Figure 5-5

Autumn Ambient Noise Levels
Taunton Energy Center

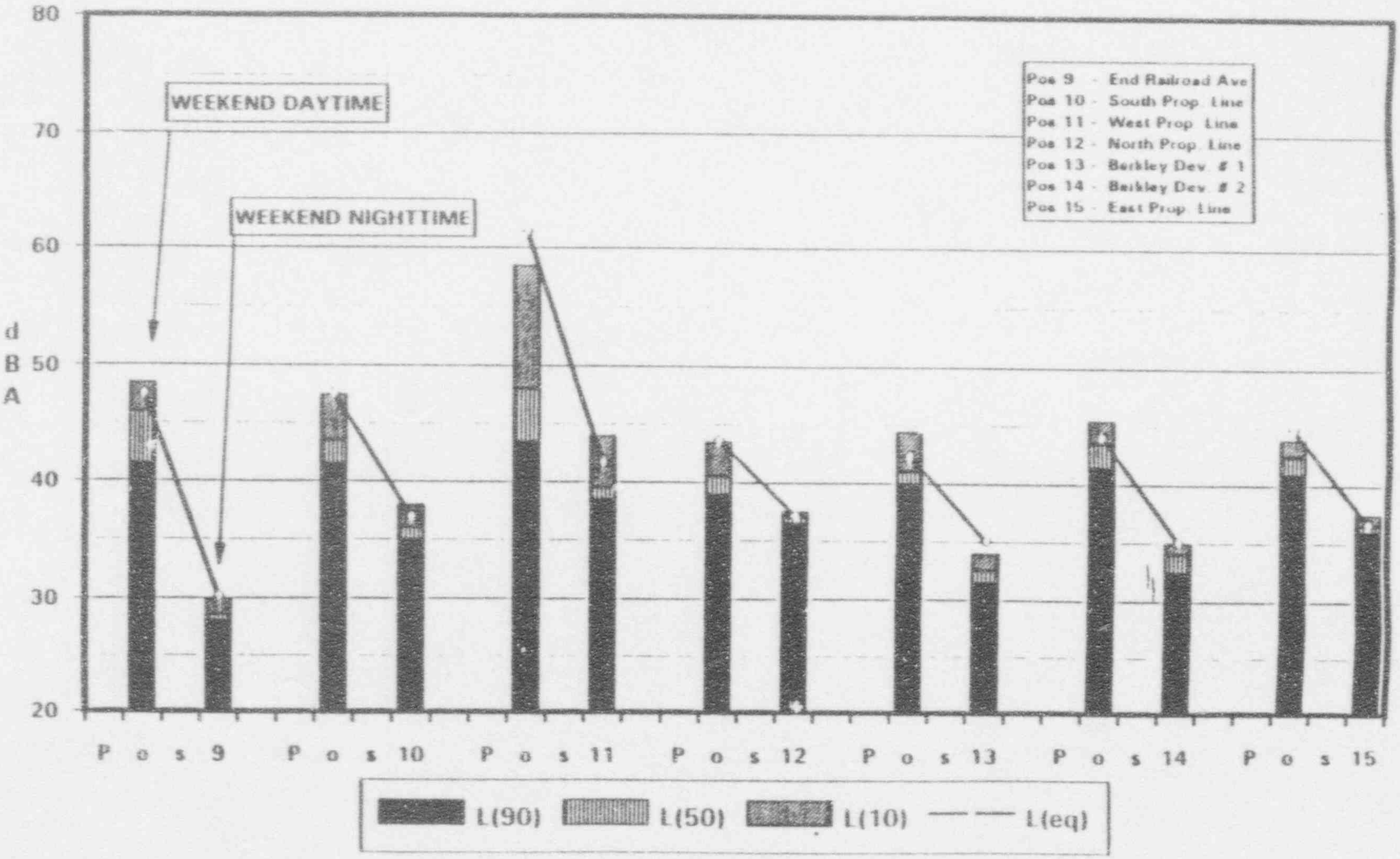


Source: Taunton Energy Center, 1992a. Major Comprehensive Plans Approval Application. Revised Noise Levels Assessment. Prepared by HMM Associates, January, 1992.

Figure 5-5

Autumn Ambient Noise Levels

Taunton Energy Center



6.0 ENVIRONMENTAL CONSEQUENCES OF THE PROPOSED ACTION

The following sections provide information on projected environmental impacts or consequences of the proposed action. The information presented is based on the analyses conducted by the project proponent and independently reviewed by EPA. In accordance with NEPA, direct, indirect, and cumulative impacts were evaluated for each impact area.

The most important potential indirect impact of the proposed Taunton Energy Center is the development of the food-grade carbon dioxide (CO_2) plant adjacent to the power plant. However, this CO_2 facility is considered to be an integral part of the TEC, as its presence allows the TEC to meet PURPA requirements as a Qualifying Facility. The facility's traffic, wastewater, air emissions, noise, visual, wetlands and other impacts have been incorporated into the overall facility impacts sections.

Beyond the CO_2 plant, the Taunton Energy Center is not expected to attract or promote significant new industrial or commercial development to the immediate site vicinity. There are no additional proposed steam hosts or co-located industrial facilities with the project area (the surrounding land is primarily owned by TMLP), and the bulk of the TEC's non-TMLP power output (120 megawatts) is not intended for local use, but will most likely be directed into the New England Power Pool's regional electrical grid.

It is possible that some ancillary businesses may be attracted by the proposed CO_2 plant (e.g. fire extinguisher services, beverage bottlers, and other CO_2 users) (Silver City Energy, 1991a). While the exact magnitude and location of these potential businesses is not known, they would be expected to be widely dispersed among existing industrial and commercial parks in the greater Taunton vicinity, as the CO_2 is readily transported for off-site usage.

6.1 Land Use

The construction of this power plant will convert an existing disturbed, former gravel mining operation and associated rail yard to new, heavy industrial uses. Existing successional vegetation and abandoned rail lines will be removed to allow construction of power plant structures, rail facilities, and coal storage facilities. This proposed change in land use represents a more intensive industrial use of the existing land area and also increases the potential for impacts to surrounding residential land uses (on Railroad Avenue and Route 138 to the south and west of the site). The area is zoned as an Open Space Conservancy District and Suburban Residential District (along Somerset Avenue), but is fully owned by TMLP, which reduces the availability of this land for other non-utility uses (Taunton Board of Zoning Appeals, 1991).

In view of these potential impacts, the proponent was required to obtain several municipal clearances from the City of Taunton. The proposed land use required variances from the City of Taunton's zoning ordinance and Special Hazard District ordinance in order to allow the 397-foot project exhaust stacks and construction of the cooling towers in a portion of the floodplain. Approval of these variances were obtained by the proponent in April, 1991 (Taunton Zoning Board of Appeals, 1991). The proponent also obtained approval of the project site plan from the Taunton Municipal Council in May, 1991 (Taunton Municipal Council, 1991).

Given the character of the immediately adjacent land use for electric power generation (i.e. TMLP's Cleary Flood Station), the local and state conditions for maintaining adequate buffers and proper facility operation and monitoring, and additional mitigation measures to reduce visual, noise, and other impacts (see Section 7) the action is not viewed as a significant impact on surrounding land use. The project is also not expected to displace any existing land uses, or preclude the future development of other adjacent land uses.

No significant secondary or cumulative land use impacts are expected from development of this facility. The rehabilitation of the rail spur south from Taunton Center to the project site may serve to encourage unspecified future rail corridor improvements and associated industries to the south of the project site. Conrail and EOTC have investigated the possibility of restoring commuter rail service south to Fall River, using the present track right-of-way, but no detailed environmental and design analysis has been completed. It is possible that private industrial development could be attracted to an upgraded rail corridor near the project site, but no upgrade is proposed by the applicant beyond the project site, and additional work would require detailed design and environmental review by Conrail and/or MBTA prior to approval.

6.2 Site Drainage and Stormwater Flows

6.2.1 Runoff Analysis

The sub-watershed of the affected site area is approximately eighteen acres. The plant facility will occupy approximately sixteen acres and the cooling tower will occupy two acres. The runoff from the sixteen-acre area will be collected in one permanent stormwater management basin located within the site boundary. No excess runoff is expected to be generated in the cooling tower area since all rainfall incidental to the tower itself will be contained within the tower. The runoff from the remaining unaffected area within the plant property limits should remain unaffected.

Runoff calculations for the project site and the surrounding area were made for pre-development and post-development conditions (Taunton Energy Center, 1991a). Determination of runoff and peak flows was based on the USDA/SCS Technical Release No. 55, "Urban Hydrology for Small Watersheds" and the U.S. Army Corps of Engineers, Flood Hydrograph Package, HEC-1.

The peak discharges from the outlet structures along with the infiltration from the basin to the wetland/river system are expected to result in close to pre-development peak flow rates. These flows are insignificant compared to Taunton River flows during the same return events. The discharges from the project site make up less than 0.1 percent of Taunton River flows during the 10-, 25-, 50-, and 100-year storm events. Thus, the effect of plant discharge on river flood levels is expected to be insignificant.

6.2.2 Stormwater Management System

The stormwater management basin has been designed to maintain the pre-development stormwater runoff rates and characteristics. In an effort to improve runoff quality, the stormwater management basin will collect and recharge all stormwater associated with storm events up to the 2-year frequency. Stormwater runoff from the newly added impervious surfaces will be collected and conveyed to the detention basin/wetland utilizing a system of curbing, catch basins, and underground piping. The bottom of the basin will be planted with wetland species that will help trap sediments and remove pollutants from the stormwater runoff to maintain the quality of runoff to the Taunton River. The basin outlet pipe will be provided with a manual control valve to prevent any discharge to the wetlands in the event of a petroleum or other hazardous material spill and also to control the release, if needed.

No significant indirect impacts to adjacent, downstream areas are expected from the facility because the stormwater runoff will be directed to a retention basin, prior to release into the existing TMLP discharge canal. No significant downstream impacts are expected from this discharge, as peak rates (discussed above) are a minimal amount of total Taunton River flow rates.

6.3 Taunton River

6.3.1 Taunton River Flows

The Massachusetts Chapter 21G permit application filed for the proposed facility registered an average withdrawal, for cooling tower makeup, of 2.95 million gallons per day (MGD). The project proponents have estimated that the Taunton River at the project site has a safe yield of 39.4 MGD (Taunton Energy Center, 1991b). The Commonwealth is currently establishing a record of water

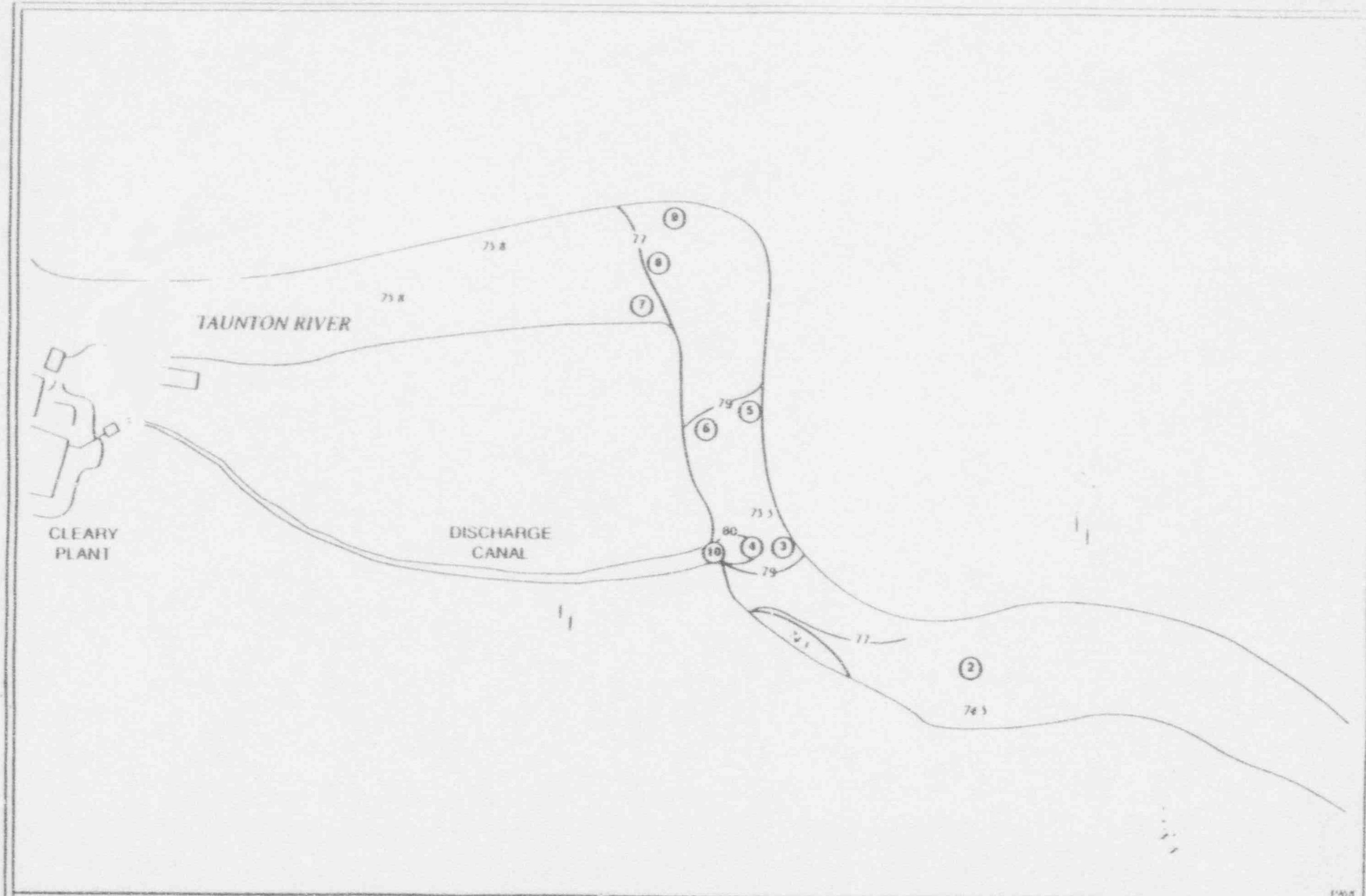


Figure 6-1
TEMPERATURE DISTRIBUTION (°F) SENSOR AT 9" DEPTH
AUGUST 27, 1975 - HIGH SLACK

withdrawal from the river basins of the state through the 21G application process. A total increase of 27.71 MGD has been registered for possible withdrawal from the Taunton River. The net consumptive loss from the Taunton River upstream of the proposed project site is approximately 11.45 MGD (Taunton Energy Center, 1991b). A comparison of the requested consumptive losses of 11.45 MGD to the safe yield of 39.4 MGD for the project site, indicates that there is an ample margin for the requested 2.03 MGD consumptive use by the Taunton Energy Center.

No indirect or cumulative impacts to Taunton River flow are expected to result from development of the TEC.

6.3.2 Taunton River Water Quality

The potential for indirect impacts is addressed in the analysis of receiving water and river ecology. Cumulative thermal and chemical impacts (e.g. chlorine) of TMLP and TEC discharges together were modeled for the Draft and Final Environmental Impact Reports (Taunton Energy Center, 1991b, 1991e).

Thermal Impacts

Maximum cooling tower blowdown temperature will be approximately 90°F. The resultant theoretical temperature increase of the mixed flows at the point of discharge under worst case summer conditions is about 0.04°F (Taunton Energy Center, 1991b). Figure 6-1 and 6-2 present the extent of the measured thermal plume resulting from operation of the present TMLP plant, during worst-case low river flow conditions (August) at both high and low tides. Because the increase in the discharge canal temperature (beyond currently permitted operating values) due to the TEC's proposed process wastewater release is expected to be minimal, these values also represent predicted maximum worst case impacts on the river. The incremental impact of the proposed discharge on the existing thermal plume is not expected to significantly impact conditions in the Taunton River.

Chemical Impacts

Dissolved Oxygen - The cooling tower blowdown is predicted to have a beneficial effect on dissolved oxygen concentrations in the Taunton River because the wet counterflow cooling tower will aerate the plant cooling water. Dissolved oxygen concentration of the Taunton Energy Center process wastewater prior to discharge is expected to be approximately 7.1 mg/l, well above the Class SB standard of 5.0 mg/l.

Chlorine - The Taunton Energy Center will use chlorine as a biocide. Existing TMLP Units 8 and 9 also both currently use chlorine. This discharge is regulated under the existing NPDES permit for the facility and was found during a 1989 total residual chlorine study (Taunton Energy Center, 1991e) to be well below levels which would impact the river.

Chlorine application rates and operating procedures for the Taunton Energy Center would be similar to those now implemented by TMLP and residual chlorine is not expected to exceed maximum effluent limitations established during the NPDES permitting process.

Total Dissolved Solids and Specific Conductance - Total Dissolved Solids (TDS) concentrations at the intake site range from 94 to 100 mg/l. Conductivity does not seem to vary with depth in the intake area, and indicates that a salt wedge does not reach the project site (Taunton Energy Center, 1991b).

Because dissolved solids will be concentrated as a result of evaporative loss through the cooling tower, TDS concentrations will be evaluated through the NPDES permit requirements. The EPA currently does not have general limits for total dissolved solids. However, EPA does recommend limits for some constituents of TDS. At present, these are limited to maximum concentrations for chlorides and sulfates in domestic water supplies which are set at 250 mg/l. Sampling results indicate dissolved solids concentrations of approximately 30 mg/l of chloride and 13 to 43 mg/l of sulfate in the Taunton River intake water at the site. Concentrations of chloride in both the cooling water blowdown and the associated processes waste streams does not exceed the EPA recommended limit for drinking water supply. The concentration of sulfate in the associated processes waste stream does exceed the EPA recommended limit for drinking water supply. However, after mixing with the large volume of the cooling tower blowdown, sulfate concentration drops below the EPA recommended limit for drinking water supply.

Nutrients - Ambient concentrations of nutrients (total phosphorus and total nitrogen) in the area of the Taunton River near the proposed discharge are elevated. Total phosphorus concentrations are approximately 0.5 mg/l, and total nitrogen concentrations are approximately 1.5 mg/l (Taunton Energy Center, 1991b). The proposed discharge is not expected to significantly change these concentrations; however, the NPDES permit will include limits for phosphorus and nitrogen to ensure compliance with federal and state water quality standards and criteria.

Alkalinity. The 1986 Taunton River survey showed alkalinity to be approximately 26 mg/l, approximately 6 mg/l above the EPA recommended minimum of 20 mg/l for freshwater aquatic life (Taunton

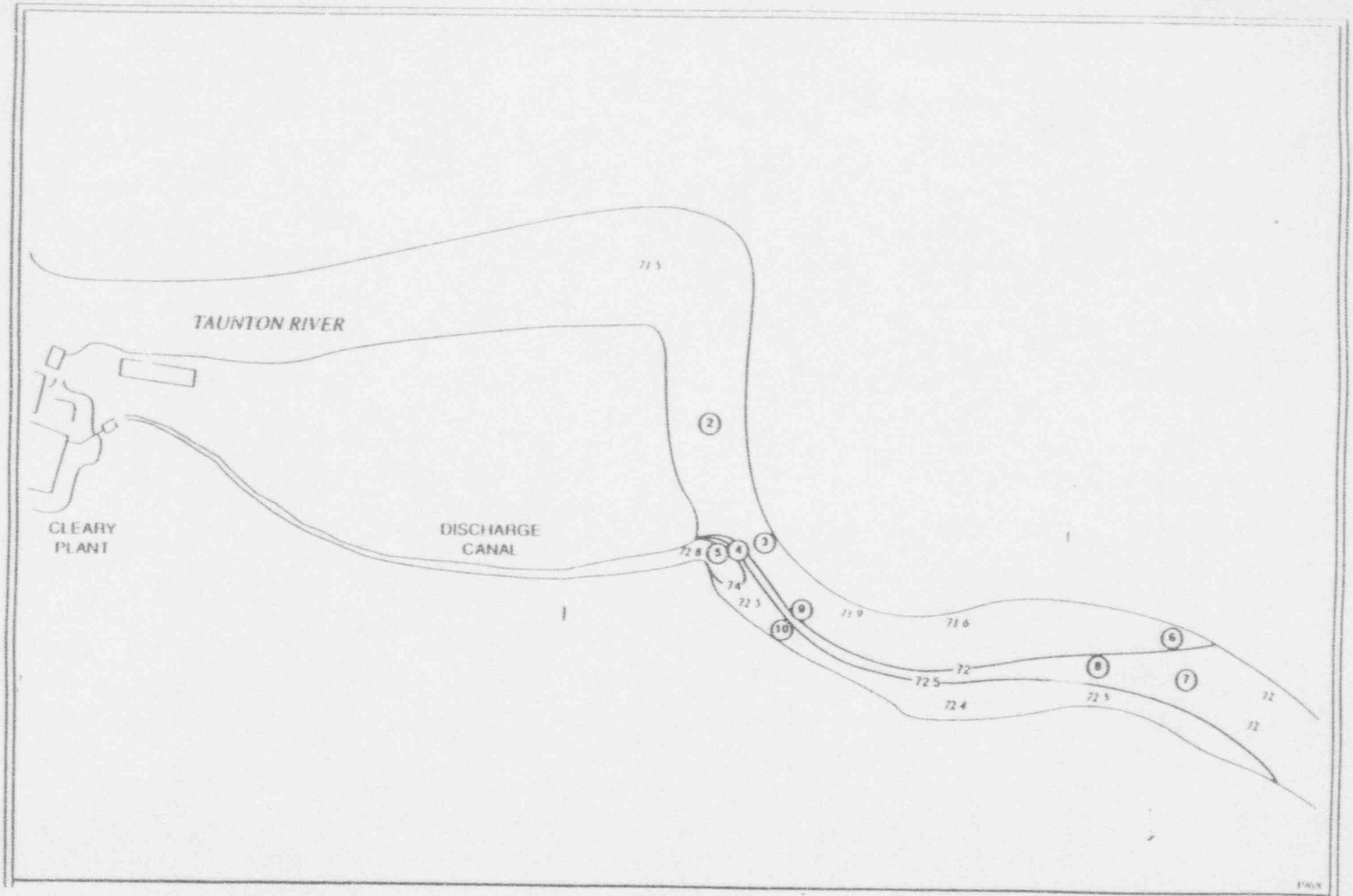


Figure 6-2
TEMPERATURE DISTRIBUTION (°F) SENSOR AT 9" DEPTH
AUGUST 27, 1975 - LOW SLACK

Source: Taunton Energy Center, 1992. 316(a) and (b) Demonstration for Taunton Energy Center. Prepared by

Energy Center 1991b). Alkalinity in the cooling tower blowdown is expected to be approximately 53.75 mg/l. This level also exceeds the EPA recommended minimum and as a result will have no detrimental effect on river water quality.

pH. pH in the Taunton River ranges between 6 and 8 (Taunton Energy Center, 1991b). Expected wastewater pH is approximately 6.4 to 6.9. Since this is within the range of existing conditions, the discharge of wastewater should have no effect on the Taunton River pH.

Total Suspended Solids. Suspended solids are not expected to be present in the process wastewater stream. As a result, there will be no adverse impacts to color and turbidity.

Oil and Grease. Oil and grease in the wastewater will be removed by an oil and water separator to a level not exceeding 15 mg/l, as required by the draft NPDES permit. Therefore, no significant impacts from oil and grease are expected.

6.3.3 Taunton River Biology

The potential impacts to fisheries resources of the Taunton River are related primarily to impingement, entrainment, or thermal discharge. These potential impacts are presented below.

Impingement Impacts

Impingement involves the inadvertent trapping of adult or juvenile fish on the exterior face of the intake structure. The proposed TEC will employ the existing TMLP intake structure. The existing TMLP NPDES permit, issued in 1988, determined that the intake structure employs the best technology available for minimizing adverse environmental impacts.

Near-plant entrainment and impingement studies were conducted at the Taunton Municipal Light Plant. The purpose of these studies was to identify and quantify the fish eggs and larvae entrained at the station, and to describe seasonal populations of finfish in the station's discharge canal.

Fish and invertebrates impinged on the intake screens at TMLP were sampled once per week by placing a wire mesh basket in the screenwash trough while the screens and wash system were operated. All fish and invertebrates large enough to be retained by the 1/4 inch mesh intake screen since previous wash were identified and counted. Fish were measured to the nearest millimeter in total length.

Impingement studies were conducted in 1975, 1990 and 1991. Sampling in the fall of 1975 showed 24 fish were impinged, most of them being alewives. Sampling in 1990 showed no fish were impinged from July to October. In December of 1990, 10 fish (2 alewives, 2 pumpkinseeds, 2 blueback herrings, 2 banded killifish, 1 four spine stickleback and 1 spottail shiner) were impinged. In January of 1991, again, a very small number of fish were impinged, primarily black crappie and blue gill sunfish.

Based on these recent field observations, minimal impingement impacts would be expected, assuming no change in velocity. Continued monitoring of impingement will be required in the NPDES permit to ensure that present intake velocities are not exceeded during operation of the facility (the results will be reviewed annually by a Technical Advisory Committee composed of state and federal agencies). If these conditions are maintained, the incremental effects of the additional water withdrawal (beyond present conditions) are not expected to result in significant impingement effects.

Entrainment Impacts

Entrainment involves the entrapment of fish eggs and larvae in the intake stream. Fish eggs and larvae entrained by the once-through cooling water system at TMLP were sampled once per week in the summer and once per month in the fall of 1990 (Taunton Energy Center, 1991b). Entrainment sampling in the discharge canal indicated that ichthyoplankton were uncommon during the time period between July and December of 1990. No fish eggs or larvae were taken on seven of the eleven collection dates. Largest collections were obtained on July 24 when larval sunfish (*Lepomis* spp.) and anchovy (*Anchoa* spp.) were present with mean densities of 29 and 18 larvae per 100 m^3 of water, respectively.

Based on the results of these sampling programs, the numbers of icthyoplankton entrained as a result of the existing TMLP operation appear to be minimal. No eggs or larvae were taken on seven of the eleven sampling occasions between July and December 1990 (Taunton Energy Center, 1991b). Therefore, the overall impact of entrainment to fish populations in the vicinity of the site is expected to be negligible assuming no change in velocity.

Thermal Discharge Impacts

The Massachusetts water quality criteria for Class SB waters state that water temperature shall not exceed 85° F (29.4° C) nor shall the rise due to a discharge exceed 5° F (1.8° C) (314 CMR 4.00). The increase in the discharge canal temperature due to the proposed project's process wastewater release is expected to be minimal, as discussed below. Maximum cooling water blowdown temperature will be approximately 90° F. On a worst case basis, this heat load, discharged at 350 gpm, represents 1.3% of existing TMLP flows. When this new discharge is superimposed on the existing TMLP heat load caused by Unit 8 discharge flows of 26,000 gpm (at 90° F) with an average August peak discharge temperature of 87° F, the resultant theoretical temperature increase of the mixed flow is approximately 0.04°. The negligible increase in discharge temperature caused by blowdown from the proposed project cooling tower is not expected to cause any additional impacts over those currently existing from Unit 8. Therefore, temperatures at the mouth of the discharge canal should not exceed the NPDES permit maximum of 90° F, and no significant change in the effects of thermal plume on conditions in the Taunton River is anticipated (See Figure 6-1).

Other Effluent Impacts

No fish kills are expected to result from cold shocks from sudden power plant shut downs. Cold shocks have not been observed in the past, despite the intermittent operation of one TMLP unit even in the winter months.

6.4 Wetlands and Floodplain

The proposed project has been designed to minimize impacts to wetlands and will not significantly alter any wetland area protected under Section 404 of the Clean Water Act. The project proponent has committed to avoid wetlands impacts during construction of over 4900 feet of sewer line. Alterations in the buffer zones have been avoided wherever possible. Predicted short-term and long-term impacts to each wetland are presented below, based upon data supplied in the project Notice of Intent (Taunton Energy Center, 1991f).

Indirect impacts from facility construction to downstream off-site wetlands are not expected to be significant, due to the conditions imposed on the applicant for erosion and sedimentation controls. The cumulative impacts of the proposed site's runoff, combined with existing flows to these wetlands will also be minimized, due to the use of the stormwater detention basin and appropriate site drainage design features (e.g. gross particle separators for road and parking area catch basins).

6.4.1. Potential Wetlands Impacts

This section discusses the potential impacts expected at each of the eight wetlands found at the project site (see Figure 5-1). Potential direct and indirect wetlands effects are summarized in Table 6-1. Vegetation identified within these wetlands, and the species' status as indicators of wetlands, is shown in Table 6-2.

Wetland 1. No direct wetland disturbance of this wetland is proposed. However, the wetland may be indirectly impacted during construction by a number of construction activities which are proposed within the 100-foot buffer zone of this wetland. These

Table 6-1

WETLANDS AND BUFFER ZONE POTENTIAL EFFECTS

Wetland #	Direct Disturbance[1]	Buffer zone[2]
Wetland 1	none	73,000 sq ft
Wetland 2	none	1,500 sq ft
Wetland 3	none	5,300 sq ft
Wetland 4	none	2,500 sq ft
Wetland 5	11000 sq ft[5]	n/a[3]
Wetland 6	none	n/a[3]
Wetland 7	none	80,000 sq ft
Wetland 8	none	TBD[4]

[1]Activities potentially subject to regulation under Section 404 of the Clean Water Act

[2]100-foot buffer zone regulated under 310 CMR Part 10.00

[3]Wetland not regulated under Massachusetts Wetlands Protection Act; no buffer zone

[4]No data provided by applicant

[5]Includes discharge of fill material, excavation, and re-grading of present wetland acreage

Source: Taunton Energy Center, Notice of Intent, August 1991

Table 6-2. (Continued)

VEGETATION IDENTIFIED IN WETLANDS DELINEATED ON PROPERTY FOR THE TAUNTON ENERGY CENTER

COMMON NAME	SCIENTIFIC NAME	INDICATOR STATUS*				
		OBL	FACW	FAC	FACU	UP
Red Raspberry	Rubus ideaus			X		
Elderberry	Sambucus canadensis		X			
Woolgrass	Scirpus cyperinus	X	X			
Common Greenbrier	Smilax rotundifolia			X		
Rough-Stemmed Goldenrod	Solidago rugosa			X		
Lanced-Leaved Goldenrod	Solidago graminifolia			X		
Hardhack (Steeple-Bush)	Spiraea tomentosa		X			
Skunk Cabbage	Symplocarpus foetidus	X				
Poison Ivy	Toxicodendron radicans			X		
Common Cattail	Typha latifolia	X				
American Elm	Ulmus americana		X			
Highbush Blueberry	Vaccinium corymbosum		X			
Northern Arrowwood	Viburnum recognitum			X		
Violet	Viola spp.		X			
Grape	Vitis spp.					

* Wetland Indicator Status Categories Used by National Wetlands Inventory:

Indicator Status	Indicator Symbol	Definition
OBLIGATE	OBL	A plant species that is always found in wetlands under natural conditions (frequency greater than 99% of the time), but which may persist in areas converted to uplands (non-wetlands) or exist in upland sites if planted there by man.
FACULTATIVE WETLAND	FACW	A plant species that usually (67% to 99% frequency) is found in wetlands, but which may be found occasionally in non-wetlands.
FACULTATIVE	FAC	A plant species that sometimes (33% to 67% frequency) occurs in wetlands, but which also occurs in uplands.
FACULTATIVE UPLAND	FACU	A plant species that is seldom found in wetlands (1% to 33% frequency) and usually occurs in non-wetlands.
OBLIGATE UPLAND	UP	A plant species that almost always (frequency greater than 99% of the time) occurs under natural conditions in non-wetlands in this region.

Source: Taunton Energy Center, 1991f. Notice of Intent for Taunton Energy Center, Prepared by HMM Associates, August, 1991, Concord, MA.

Table 6-2.

VEGETATION IDENTIFIED IN WETLANDS DELINEATED ON PROPERTY FOR THE TAUNTON ENERGY CENTER

COMMON NAME	SCIENTIFIC NAME	INDICATOR STATUS* OBL	FACW	FAC	FACU	UP
Red Maple	Acer rubrum		X			
Yarrow	Achillea millefolium				X	
Speckled Alder	Alnus rugosa		X			
Sarsparilla	Aralia spp.				X	
Milkweed	Asclepias spp.					
Gray Birch	Betula populifolia			X		
Sedges	Carex spp.					
Coast Pepperbush	Clethra alnifolia			X		
Silky Dogwood	Cornus amomum		X			
Red-Osier Dogwood	Cornus stolonifera		X			
Spotted Joepyeweed	Eupatoriadelphus maculatum		X			
Joepyeweed	Eupatorium dubium					
Boneset	Eupatorium perfoliatum		X			
White Ash	Fraxinus americana				X	
Canadian Johnswort	Hypericum canadense		X			
Jewelweed	Impatiens capensis		X			
Blue Flag	Iris versicolor	X				
Soft Rush	Juncus effusus		X			
Red Cedar	Juniperus virginiana				X	
Spicebush	Lindera benzoin		X			
Purple Loosestrife	Lythrum salicaria		X			
Canada Mayflower	Maianthemum canadense			X		
Black-Gum	Nyssa sylvatica			X		
Sensitive Fern	Onoclea sensibilis		X			
Cinnamon Fern	Osmunda cinnamomea		X			
Deer-Tongue Grass	Panicum clandestium			X		
Virginia Creeper	Parthenesisis quinquefolia		X			
Reed Canarygrass	Phalaris arundinacea		X			
Common Reed	Phragmites australis		X			
Pokeweed	Phytolacca americana				X	
White Pine	Pinus strobus				X	
Tearthumb	Polygonum sagitatum					
Quaking Aspen	Populus tremuloides				X	
Black Cherry	Prunus serotina				X	
White Oak	Quercus alba				X	
Pin Oak	Quercus palustris		X			
Smooth Sumac	Rhus glabra					
Staghörn Sumac	Rhus typhina					
Multiflora Rose	Rosa multiflora				X	
Swamp Dewberry	Rubus hispidis		X			

- Continued -

include construction of a railway retaining wall, cooling tower facilities, a stormwater discharge outlet and pipe, coal thaw shed, coal unloading building and conveyor system, and effluent discharge pipe. In addition, a compensatory floodplain storage area will also be constructed in this wetland's 100-foot buffer zone. The impacts of these facilities are discussed below.

A 400-foot retaining wall will be constructed immediately west of Wetland 1, in order to stabilize the slopes for the railway access road for the facility. This wall will be constructed within the upland area adjacent to the wetland. Steel sheet piling will be used to form the base of the retaining wall, and all equipment will work from the upland side of the wall. Indirect impacts to the wetland from construction may include: (1) temporary increases in sedimentation and erosion of adjacent embankments during wall construction and re-grading of the railway embankment; and (2) temporary disturbance of wildlife usage (due to noise impacts) along the perimeter of the wetland during construction activities. As these impacts are temporary, and will be further mitigated by the installation of silt fencing and other erosion and sedimentation controls discussed in Section 7, they are not expected to be significant.

The stormwater basin outlet pipe will be installed on the western edge of the retaining wall; the end of the pipe will be located approximately 50 feet upslope of the wetland edge. Excavation and construction of the foundations for the coal unloading building, thaw shed and conveyor system may result in temporary indirect impacts to the wetland due to increases in sedimentation, and temporary disturbance of wildlife due to noise impacts from construction. These impacts are not expected to be significant, as they are short-term in nature, and will be mitigated by erosion and sedimentation controls, as discussed in Section 7. (Mitigation).

Wetland 2. No direct impacts to Wetland 2 are proposed as part of the project. Construction of the main access road and a water line for the project will disturb approximately 1,500 sq. feet of the 100-foot buffer zone. Temporary increases in erosion and sedimentation are possible during construction; these impacts will be mitigated by the placement of siltation fencing within the buffer zone and other measures discussed in Section 7. Temporary disturbance of wildlife, due to noise impacts from construction, may also occur, but these impacts are expected to be short-term.

Wetland 3. No direct impacts to Wetland 3 are proposed as part of project construction. Trees will be cleared, and some grading will be required in the 100-foot buffer zone of this wetland, in order to construct the proposed site access road. Projected buffer zone impacts of approximately 5,300 sq. feet are possible during construction. Temporary increases in erosion and sedimentation are possible during construction; these impacts will be mitigated by installing siltation fencing in the buffer zone and other measures discussed in Section 7.

Wetland 4. No direct impacts to Wetland 4 are proposed as part of this project. Grading associated with the construction of the railroad access road and siding will alter approximately 2,500 sq. feet of buffer zone within 100 feet of the wetland. Temporary increases in erosion and sedimentation are possible during construction; these impacts will be mitigated by installing siltation fencing in the buffer zone and other measures discussed in Section 7.

Wetland 5. Wetland 5 will be directly impacted by the project as a result of construction of the stormwater management basin. The existing wetland area (a man-made depression created from excavation of borrow material from an upland area) will be regraded and incorporated into the proposed stormwater basin. This basin is designed to replace the existing functions provided by this wetland (e.g. flood storage capacity and sediment stabilization). The construction of the basin will permanently remove existing wetland vegetation from the existing wetland and will result in temporary disruption of wildlife habitat, and water quality and siltation impacts (as a result of re-grading and excavation activities).

This wetland is currently subject to Federal jurisdiction under Section 404 of the Clean Water Act, but is not considered a wetland subject to jurisdiction under the Massachusetts Wetlands Protection Act, as it is not bordering an adjacent resource area and does not meet the definition of an Isolated Land Subject to Flooding. This disturbance has been reviewed by the Army Corps of Engineers under Section 404 of the Clean Water Act. The ACOE has determined that this project impact qualifies under Nationwide Permit #26 as an activity which would have minimal adverse environmental impacts (ACOE, 1991). The project proponent has prepared a wetlands re-planting program to re-create the lost wetlands functions and values (see Section 7.4).

Wetland 6. No direct impacts are proposed for this wetland. Like Wetland 5, this wetland is a hydrologically-isolated wetland which is not regulated under the Massachusetts Wetlands Protection Act, but is subject to ACOE jurisdiction under Section 404 of the Clean Water Act. As no direct impacts are proposed, additional permit review under Section 404 was not required. However, temporary increases in erosion and sedimentation are possible during construction of the upgraded railroad siding adjacent to this wetland; these impacts will be mitigated by installing siltation fencing in the buffer zone and other measures discussed in Section 7.

Wetland 7. No direct impacts are proposed for this wetland. The construction of the proposed sewer line extension and railroad right of way will disturb approximately 80,000 square feet of buffer zone within 100 feet of this wetland. In addition, an unspecified amount of buffer zone impacts may occur as a result of future, speculative plans to upgrade the rail access adjacent to the facility by Conrail and/or the Massachusetts Executive Office of Transportation and Construction (EOTC). However, these additional actions are not needed for operation of this project, and their impacts will be addressed (if pursued) in a separate analysis by those agencies. Temporary increases in erosion and sedimentation are possible during construction of the upgraded railroad siding adjacent to this wetland; these impacts will be mitigated by installing siltation fencing in the buffer zone and other measures discussed in Section 7.

Wetland 8. No direct impacts to this wetland are proposed as part of this project. However, a 4,900 foot length of 8-inch sewer line to connect the TEC facility with the existing 18-inch sewer at Baker Avenue is proposed for construction within the 100 foot buffer zone of this wetland. At two locations where the wetland abuts the proposed right-of-way, concrete retaining walls will be constructed in a manner similar to that proposed for Wetland 1. Additional work may be required within the buffer zone to relocate an existing 10" gas line in the present TMLP right-of-way adjacent to the wetland. No direct impacts to the wetland will occur as a result of this construction. Temporary increases in erosion and sedimentation are possible during construction of the upgraded railroad siding adjacent to this wetland; these impacts will be mitigated by installing siltation fencing in the buffer zone and other measures discussed in Section 7.

6.4.2 Floodplain Impacts

Work within the 100-year floodplain is expected to displace approximately 250 cubic yards of floodplain storage volume. These impacts will result from the siting of the cooling towers and stormwater discharge outlet pipe. The bulk of these impacts will result from the cooling tower facilities. The proponent stated that alternative cooling tower locations were considered, and none were available which resulted in fewer environmental impacts than the proposed location (Taunton Energy Center, 1991f).

EPA has conducted an independent review of site layout in order to assess the availability of alternatives to the proposed location. This review was required in order to meet the requirements of Executive Or[illegible] 1198[illegible] which states that federal agencies shall, in their decision-making process, investigate alternatives to actions which may adversely impact a floodplain's ability to store and reduce impacts during flood events. The results of this analysis are provided below.

The location of the cooling towers within a power plant layout is governed by two key factors, operational requirements and potential environmental impacts. From an operational standpoint, the towers should be closely coupled with the turbine and boilers for the facility to minimize the length of interconnecting piping and pumping requirements. From an environmental standpoint, the towers should be located as far as possible from (1) existing residences and other sensitive receptors, in order to reduce noise and aesthetic impacts; (2) highways and other roads, to reduce potential traffic safety problems due to fogging from the cooling tower plume; and (3) wetlands and floodplains, due to the flood storage capacity and other benefits provided by these areas.

The overall site layout is primarily governed by the location of the adjacent TMLP plant, the railroad right-of-way, and adjacent residences (see Figure 5-1). Given this layout, the cooling facilities are positioned at an optimal location to meet the plant's operation requirements, and contain an appropriate number of cooling tower cells for this proposed plant size. Shifting the towers north would not reduce the floodplain impacts, due to the elongated east-west configuration of the floodplain at that location. In addition, this would result in impacts to and possible relocation of existing TMLP facilities. Moving the cooling tower cells to the south or east of their present location would result in direct wetlands impacts (unlike the present location), and increased floodplain impacts. The existing oil storage facility to the north of the proposed site prevents location of the cooling towers in that location. The towers could potentially be shifted to the west of the proposed turbine and boiler buildings. However, this location is closer to existing residences (approximately 1200 feet) and roadways, resulting in higher noise impacts (as a result of the tower fans and associated machinery) and visual impacts resulting from the towers and evaporative plumes. In addition, the cooling tower plume would be more likely to cause localized fogging of existing and proposed roadways if sited at this location.

Thus, there are no substantially preferable site alternatives which result in lower overall environmental impacts for these cooling tower facilities. In addition, because floodplain heights at the project location are driven in part by tidal forces, the percentage of lost floodplain storage is not expected to result in significant increases in flooding severity or frequency. Mitigation which has been proposed by the applicant to replace (at a 1.4:1 ratio) the lost flood storage capacity has been approved by the Taunton Conservation Commission and certified by Massachusetts DEP in the project Order of Conditions (Taunton Conservation Commission, 1992). This mitigation, described in Section 7.4, is expected to be sufficient to compensate for the minor floodplain impacts from the project.

6.5 Tidelands and the Coastal Zone

Although the project is located outside the Coastal Zone as represented in the 1977 *Massachusetts Coastal Zone Management Atlas*, the project will draw water from and discharge process water to the Taunton River, a mapped coastal resource. Therefore, a CZM consistency review will be required. A complete MCZM Federal consistency statement, detailing the project's consistency with the applicable MCZM policies, will be prepared and filed with the MCZM office, along with copies of the Federal permit applications. MCZM requires this formal review of Federal permitting actions for projects that are located within or have the potential to affect the adjacent Coastal Zone.

The use of the existing intake structure and discharge canal will minimize additional impacts on tidelands. The only component of the proposed project that may require licensing under Chapter 91 is construction of an additional outfall on the existing TMLP headwall at the discharge canal. The proponent will request a determination from DEP Waterways staff to determine if a Chapter 91 license will be required for this activity, based on their review of the licensing history and jurisdictional findings. The CZM consistency review is currently ongoing, but the project is expected to comply with each of the applicable CZM policies, and thus no significant impacts to coastal zone resources are expected.

No indirect or cumulative impacts to tidelands and the coastal zone are expected.

6.6 Rare and Endangered Species

The Taunton Energy Center is not expected to have any adverse impacts on the Northern diamondback terrapin or its habitat. As discussed in Section 6.3, no significant changes in the existing water quality conditions of the Taunton River are expected immediately adjacent to the site and no effects should be evident one mile downstream in the mapped terrapin habitat area. Also, no change in water flows or downstream floodplains is expected.

No shortnose sturgeon were found during the studies conducted by the U.S. Fish & Wildlife Service in 1991 and 1992. Three Atlantic sturgeon were found, one during the 1991 study and two in June of 1992. The fish were juveniles and were probably migrating to this area to feed (Kynard, pers. comm., 1992). No significant impacts to either species of sturgeon are expected, and the National Marine Fisheries Service has advised EPA that there is no need for further consultation pursuant to Section 7 of the Endangered Species Act.

6.7 Visual Resources

In order to assess the visual impact of the proposed facility on surrounding areas, a number of representative vantage points were selected for illustration of pre and post-construction conditions (Taunton Energy Center, 1991b).

These points were generally chosen based on the number of people that could be affected by the view or based on the relative impact of the new facility on the existing view. Each vantage point was selected so that the existing TMLP stacks were visible from it. This provides a point of reference for the viewer and enables a comparison of the view before and after construction. Each vantage point was photographed. The existing topography was entered into a computer, and using computer-assisted drafting capability, three dimensional line drawings were generated of the project as it would appear from each vantage point. Working from photographs, an artist then prepared a rendering of the project site, including the TMLP as it appears under existing conditions, in the proper scale and perspective.

In View 1, from the entrance to the facility, only the top portion of the new stack is seen over the existing treeline.

In View 2, from Railroad Avenue, the proposed project is visible and causes the most significant change from existing conditions. The coal storage building is the dominant feature in this view. The top of the boiler building and much of the stack are visible behind the coal storage building. The existing TMLP facility is entirely blocked from view.

In View 3, from Berkeley Street, the new facility can be seen on the horizon in the background, but is screened to a large extent by a treeline in the mid-foreground.

From View 4, the apparent size and scale of the proposed facility is similar to the existing view.

In View 5, from the Taunton River, the new facility is screened to a significant extent by the treeline in the mid-foreground.

The above visual analysis presents the impacts of the facility on areas of private open space near the project site. However, the proposed stack may be visible, at a distance, from several areas of public open space; these views are generally less imposing than the views presented for the above selected vantage points. On Baker Road, west of Somerset Avenue, the Taunton Sports Club has a view of the existing stack. The visual impact on this area of open space will be generally comparable to, or less than, the view from View 1 at the TMLP entrance. Boyden Wildlife Refuge is approximately 0.75 miles from the proposed facility; however, the proposed stack is not expected to be visible from that location. The Bristol County Golf Course is approximately 2.25 miles northwest of the project site. By comparison, View 3 is 3,400 feet from the project site and visibility from the golf club will be even less than in View 3.

The Taunton River is also an important area of open space, however, immediately adjacent to the project site, views to the west are dominated by the Unit 9 cooling tower and the existing TMLP facility. Further south, the views of the proposed facility are largely blocked by the near-field trees.Because the existing TMLP facility is in the foreground, it will continue to dominate views from that vantage point. Further south, the TMLP and proposed TEC facilities are largely blocked by the near field trees.

Based on the above analysis, the Taunton Energy Center is not expected have significant direct, indirect, or cumulative visual impacts.

6.8 Recreational Resources

The development of the Taunton Energy Center is not expected to adversely affect recreational access to the Taunton River, but the proponent recognizes that additional access to the river is a desirable amenity for the citizens of Taunton and neighboring communities and is committed to providing that additional access. A plan has been developed to promote access to the river and is currently being evaluated by the city and the Taunton River Watershed Alliance. The meetings identified the possibility of developing of a canoe landing for public access to the Taunton River. In addition, the Taunton Energy Center will also participate in a tree-planting program, providing visual and open space benefits to Taunton and surrounding communities (Taunton Municipal Council, 1991).

No indirect or cumulative impacts to recreational resources are expected.

6.9 Historic and Archaeological Resources

The existing TMLP stacks are not visible from the historic Peter Walker House (within a mile of the project site), nor are the stacks from the proposed facility expected to be visible. In addition, because the proposed project will be located south of the existing plant, no impacts on the Blake Cemetery are expected from the proposed project.

In view of the lack of historic resources in the immediate vicinity of the project site, the disturbance of site terrain due to the previous gravel mining operation, and the fact that the wooded lots owned by TMLP will be retained as buffer zone, the Massachusetts

Historical Commission concluded that the project should not have any impact on historic or archaeological resources and no further study is required (Bell, pers. comm., 1992). In addition, no indirect or cumulative impacts to any historic or archaeological resources are expected.

6.10 Traffic

EPA has independently reviewed an analysis prepared by the project proponent of traffic conditions at the site during existing conditions (1990), the year of peak construction (1993), and the year of commencement of operations (1995) (Taunton Energy Center, 1991b). The analysis was conducted in accordance with the July, 1989 *Revised EOEA/EOTC Joint Guidelines for EIR/EIS Traffic Impact Assessment*. Although the project schedule has changed and the timing of the construction peak and commencement of operations is now expected to be delayed one to two years, the traffic analysis performed still provides a good comparison of predicted conditions for those points during project construction.

Future Conditions Without the Proposed Project

Background Traffic Growth. A background traffic growth figure of 2 percent per year was used to account for normal increases in traffic that typically occur in a healthy economy. This figure was developed based on conversations with the City of Taunton Community Development Office, City Engineer, and the Southeastern Regional Planning and Economic Development District.

1993 Construction Year No-Build Traffic Operations. The existing 1990 peak hour traffic volumes were adjusted to 1993 conditions using the 2 percent per year growth factor. These volumes were used to calculate the LOS at the intersection of Somerset Avenue and the TMLP Driveway. There is no predicted decrease in LOS at this intersection between 1990 and 1993.

1995 Operations Year No-Build Traffic Operations. Using the two percent per year growth factor, the existing 1990 peak hour traffic volumes were adjusted to 1995 conditions. These volumes were then used to calculate the LOS during the same AM and PM peak hours . The results of this analysis show that there is no predicted decrease in LOS at this intersection.

Future Conditions With the Proposed Project

Due to delays in the project schedule, construction of the facility (originally slated to begin in the Spring of 1992) is now expected to begin in Spring 1993 or 1994 and last approximately three years. It is expected that the peak number of workers on-site will occur in late 1994 or 1995. During this period the number of workers will be approximately 750. On-site construction activity will occur primarily in one shift, from 7:00 AM to 4:00 PM. Truck traffic is expected to peak at about 50 trips per day during construction and will be restricted to between the hours of 8:00 AM and 4:00 PM.

During construction, the number of daily trips generated will total 1,050. This includes both construction workers (500 trips in, 500 trips out) and truck traffic (25 in, 25 out). During the peak construction period, the site drive will operate at LOS D during the PM commuter peak hour. This LOS applies only to vehicles exiting the site. Traffic entering the site from Somerset Avenue will experience LOS A conditions with through traffic on Somerset Avenue experiencing little or no delay. Construction traffic will be limited, where possible, through the use of rail to deliver construction material. This measure, together with the scheduling of arrivals and departures for the construction work shift to fall outside of the commuter peak hours, should cause minimal impacts to the surrounding roadway network.

During plant operation, the majority of trips generated by the proposed project will be employee trips to and from the site. The plant will operate 24 hours a day and the arrival and departure times of the employees will vary. The only shift that coincides with the AM or PM peak hour of the adjacent street is the 8:00 AM to 5:00 PM shift. The other shift changes occur outside either of the peak hours. Taking the worst case, it was assumed that all 11 employees would arrive during the commuter peak hour.

In addition to the employee trips, a limited number of deliveries to the site can be assumed. Delivery hours will be between 8:00 AM and 3:30 PM. Limestone will be delivered to the plant by truck and will generate 19 two-way trips per day. This corresponds to approximately three two-way trips per hour.

Nine grade crossings in Taunton will be used by arriving and departing unit coal trains. Four grade crossings are located on minor streets. These streets are not used by through traffic. Potential traffic impacts at these four crossings are limited to residents of those streets, impacting few vehicles at off-peak hours. The schedule of train arrivals and departures at these four crossings shall be published. The Police Department, Fire Department, School Department, Department of Public Works, and Mayor's Department shall be notified of changes in the published schedule.

Five of the grade crossings were identified as having high traffic volumes. These include: Weir Street, Somerset Street (Route 138), Winthrop Street (Route 44), Oak Street (Taunton Mall), and Tremont Street (Route 140). The schedule proposed for the unit coal trains indicates that the inbound train will pass through downtown Taunton on Conrail's Middleboro Secondary Track approximately once each week, at about 6:30 AM, and the outbound train will pass through downtown Taunton the same evening at approximately 9:45 PM.

The average delay to traffic at these grade crossings will be three minutes. This average delay is based on a posted train speed of 10 mph and a unit coal train length of one mile, resulting in a six minute maximum street blockage, and the random arrival of vehicles during the six minute blockage. This will occur twice per week, once in the early morning and once in the evening. Standard Conrail procedure will be used to notify municipal authorities in advance of the passage of the train, so that police may be aware of its arrival. Additionally, Taunton Energy Center has committed to coordinating and funding the situating of an ambulance at the side of the coal train route opposite the ambulance dispatch location for the duration of each arrival and departure of the train. An emergency number will be provided, on each publication of schedule, that can be called to stop a train from entering the City or departing the power plant site during an emergency (Taunton Municipal Council, 1991).

Overall, the proposed project is expected to have minimal impact (either direct, indirect, or cumulative) on traffic once it is operational. The intersection of the TMLP driveway and Somerset Avenue will continue to operate at better than LOS C during both the AM and PM commuter peak hours. The new site drive will likewise operate at LOS C or better for the same periods.

6.11 Rail

Potential impacts of rail service include noise and vibration, air quality, and traffic delay. These impacts are addressed in this report under the Noise, Air Quality, and Traffic sections, respectively. Traffic delays can occur at street grade crossings. Air quality impacts involve particulate emissions and exhaust emissions from locomotives. The locomotives that would be used are unusually quiet SD-40 locomotives and comply with applicable federal guidelines.

Coal would be brought in by train weekly. The coal unloading operation has been designed to make most efficient use of the rolling stock, so that the train may depart the same day it arrives. The outgoing train would be used to remove ash. The route for the unit coal trains to and from the Taunton Energy Center will involve one rail carrier, Conrail, from origin to destination.

The Taunton Energy Center will guarantee unobstructed passage for trains if the rail spur extending south from the project is ever restored to use, in accordance with a commitment between the Taunton Energy Center and the Massachusetts Executive Office of Transportation and Construction (EOTC) (HMM Associates, 1992c).

As mentioned previously, the possible future development of the rail right-off-way south of the plant could result in potentially significant rail traffic increases. While the rehabilitation of the track section south from Weir Avenue to the project site could eventually assist in future rail line development, the TEC project alone will not provide sufficient economic impetus or incentive for development of this rail line. The magnitude and location of future off-site rail or related industrial development is highly speculative at this time and dependent upon planning undertaken by Conrail, MBTA, and EOTC.

6.12 Air Quality

Compliance with Applicable Standards

Under the Federal Clean Air Act (as amended in 1990) and Massachusetts regulations at 310 CMR Part 7.00, the Taunton Energy Center is classified as a major source due to its potential for emitting greater than 100 tons per year of several regulated pollutants. As a major source, the project must also comply with federal New Source Review procedures (including Prevention of Significant Deterioration (PSD) and New Source Performance Standard Review) and Massachusetts Air Quality Policies which are incorporated into the Commonwealth's Air Quality Plans Approval process.

The National Ambient Air Quality Standards (NAAQS) and DEP's Air Toxics Policy (which establishes Allowable Ambient Levels (AALs) for over 100 toxic air pollutants) are health-based limits, intended to be protective of public health and safety. These limits have been established through extensive and comprehensive risk analysis. Thus, potential public health impacts are also addressed through compliance with these standards.

The federal Clean Air Act underwent significant amendment in 1990. To date, few new regulations have been promulgated as a result of those amendments. However, some provisions of the 1990 Amendments, such as the acid rain provisions (which involve market-based allowances to regulate sulfur dioxide emissions), may potentially affect the TEC following construction. Other provisions, such as new offset requirements for volatile organic compounds and nitrogen oxides in ozone non-attainment areas (such as the project site) still require detailed regulations and approval, through modification and approval of the Massachusetts State Implementation Plan. Thus, the potential impact of the Amendments is not fully known at this time.

The proponent conducted an evaluation of the predicted air quality impacts associated with the Taunton Energy Center which assessed compliance with ambient air quality standards, PSD increments, the

DEP air toxics policy and one-hour NO_2 guideline, odors, and additional impacts on visibility, soils and vegetation, and growth.

The results of the screening modeling for the project are shown in Table 6-3. These results indicate that the proposed facility emissions are well below the applicable NAAQS, but exceeded the regulatory significant impact levels for NO_2 and SO_2, requiring a refined modeling assessment for these emissions. The results of the refined dispersion modeling, shown in Table 6-4, indicated that the facility emissions were also below applicable NAAQS and the DEP's one-hour NO_2 policy. The refined analysis also determined the locations of significant impact areas (areas in which predicted concentrations exceed regulatory levels, triggering additional review requirements) as indicated below (Taunton Energy Center, 1991c):

3-hour SO_2:	1,300 meters
24-hour SO_2:	15,000 meters
1-hour NO_2:	1,700 meters
24-hour TSP/PM-10:	800 meters
Annual TSP/PM-10:	400 meters

The refined modeling indicated exceedances of significance thresholds requiring interactive source modeling (e.g. modeling of the TEC emissions with existing major sources, using data and methods specified by Massachusetts DEP (Taunton Energy Center, 1991c). Thus, interactive source modeling was conducted for the following pollutants and averaging periods: NO_2 (1-hour), SO_2 (3 and 24-hour), total suspended particulates (24-hour and annual) and PM-10 (24-hour and annual). The results of this interactive source modeling are presented in Table 6-5, and indicate that the combined maximum impacts from the TEC facility, other sources, and background levels, remain well below the applicable NAAQS.

The refined air quality modeling results also assessed compliance with the PSD increments. PSD increments have been developed for NO_2, SO_2, TSP, and PM-10 (proposed) and are applicable to those pollutants for which the area is designated as either in "attainment" or "unclassified." The results, shown in Table 6-6, indicate that the PSD increments will be maintained and expected concentrations due to the Taunton Energy Center are well below any levels which define significant deterioration (Taunton Energy Center, 1991c).

New Source Performance Standards

The Taunton Energy Center is subject to EPA's New Source Performance Standards (NSPS) for electric utility generating units capable of combusting more than 250 million BTU/hour. Based on a comparison of the projected plant emissions with applicable federal and state emission limits, the project is not expected to exceed the NSPS requirements, as shown in Table 6-7.

Table 6-3.

SUMMARY OF "WORST-CASE" ISCST SCREENING MODEL CONCENTRATIONS
TAUNTON ENERGY CENTER: MAIN STACK

	Concentration (ug/m^3)		
Pollutant	Proposed Facility	Significant Impact Level	NAAQS Level
Annual NO_2	2.3*	1	100
3-hour SO_2	35.9*	25	1300
24-hour SO_2	16.0*	5	365
Annual SO_2	4.0*	1	80
24-hour TSP/PM-10	1.1	5	150
Annual TSP/PM-10	0.3	1	50
1-hour CO	26.7	2000	40,000
8-hour CO	18.7	500	10,000

* Indicates that the modeled "worst-case" screening concentration is above the air quality modeling significant impact level and refined modeling assessment is required.

Source: Taunton Energy Center, 1991c. PSD/Air Plans Application for the Taunton Energy Center. Prepared by HMM Associates, April, 1991. Concord, MA.

Table 6-4.

SUMMARY OF "WORST-CASE" ISCST REFINED MODEL CONCENTRATIONS

(1983-1986, 1988)

Pollutant	Year	Proposed Facility Conc. ($\mu g/m^3$)	Distance (Meters)	Direction (Degrees)	Significance Level	NAAQS Level
1-Hour NO_2	1988	45.1*	800	20	32**	320**
Annual NO_2	198[illegible]	0.28	8000	160	1	100
3-Hour SO_2	1984	31.3*	1000	180	25	1300
24-Hour SO_2	1984	5.6*	8000	160	5	365
Annual SO_2	1983	0.48	8000	160	1	80
24-Hour TSP	1985	13.7*	200	160	5	150
Annual TSP	1986	1.94*	163	130	1	60
24-Hour PM-10	1985	13.7*	200	160	5	150
Annual PM-10	1986	1.94*	163	130	1	50

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* Indicates that maximum facility concentration is above the air quality modeling significance level and interactive refined modeling is required.

** Massachusetts DEP policy criteria.

Source: Taunton Energy Center, 1991c. PSD/Air Plans Application for the Taunton Energy Center. Prepared by HMM Associates, April, 1991. Concord, MA.

Table 6-5.

AMBIENT AIR QUALITY STANDARDS

ASSESSMENT (ug/m^3)

Pollutant	Averaging Period	Maximum Interaction Source Ambient Impact*	Distance (meters)	Direction (degrees)	TEC Contribution	Other Interaction Sources	Background Level	Ambient Standard
SO_2	2nd High 3-Hour	863.1	800	180	14.1	194.0	655	1300
	2nd High 24-Hour	181.3	6000	230	5.1	72.2	104	365
NO_2	2nd High 1-Hour	201.0**	1000	310	41.0	0	160	320
TSP	2nd High 24-Hour	81.0	126	250	1.9	12.1	67	150
	Annual	30.3	163	130	1.9	0.4	28	60
PM-10	2nd High 24-Hour	81.0	126	250	1.9	12.1	67	150
	Annual	30.3	163	130	1.9	0.4	28	50

* Includes Taunton Energy Center (TEC) facility, interaction sources and background.

** The ambient concentration is computed from those cases when the TEC facility has a predicted concentration equal to or greater than the DEP short-term significance level of 32 ug/m^3. The 2nd high value presented here is based on a value not occurring on the day that the highest value is predicted.

Source: Taunton Energy Center, 1991c. PSD/Air Plans Application for the Taunton Energy Center. Prepared by HMM Associates, April, 1991. Concord, MA.

Table 6-6.

PSD INCREMENT EVALUATION (ug/m^3)

Pollutant	Averaging Period	PSD Increment Consumed by All Sources	Increment Consumed By TEC	PSD Increment	Year	Location	
						Dist.	Dir.
SO_2	3-Hour	28.0	28.0	512	1984	1000	200
	24-Hour	4.8	4.8	91	1983	8000	10
	Annual	0.5	0.5	20	1983	8000	160
TSP	24-Hour	9.7	9.7	37	1984	207	190
	Annual	1.9	1.9	19	1986	163	130
PM-10	24-Hour	9.7	9.7	30*	1984	207	190
	Annual	1.9	1.9	17*	1986	163	130
NO_2	Annual	0.3	0.3	25	1983	8000	160

* Proposed PSD increments.

Source: Taunton Energy Center, 1991c. PSD/Air Plans Application for the Taunton Energy Center. Prepared by HMM Associates, April, 1991. Concord, MA.

Table 6-7. TEC Compliance with New Source Performance Standards

Pollutant	EPA NSPS	DEP Emission Limit	Project Emission
SO_2	1.2 LB/MMBtu and 10% of potential combustion concentration	1.1 lb/MMBtu	0.256 lb/MMBtu
NO_x	0.6 lb/MMBtu and 65% of potential combustion concentration	0.7 lb/MMBtu	0.15 lb/MMBtu
Particulates	0.03 LB/MMBtu and 1% of potential combustion concentration	0.05 lb/MMBtu	0.018 lb/MMBtu

Source: Taunton Energy Center, 1991. Draft Environmental Impact Report for the Taunton Energy Center (EOEA #8180), dated 15 February, 1991.

Other Air Quality-Related Impacts

An analysis of potential for odors was conducted by the proponent (Taunton Energy Center, 1991c). Of the constituents potentially emitted from the facility into the air, only ammonia and formaldehyde were identified as odorous. Modeling results indicate that maximum one-hour predicted concentrations of ammonia and formaldehyde are well below their respective perception thresholds as indicated in the *Handbook of Environmental Data on Organic Chemicals* (Verschueren, 1983).

Under the Clean Air Act, an assessment of the potential impacts of emissions from new major sources on visibility in Federal Class I Areas is required. Class I areas include national parks, wilderness areas, and other designated areas which require special protection of existing air quality. Because the closest Class I area to the project site is approximately 200 kilometers northwest of the project site (the Lye Brook Wilderness Area in southern Vermont) no significant impacts to Class I Areas from the proposed TEC are expected. In addition, no significant visibility impairment is predicted by the visibility analysis outside the Class I area boundary using the EPA VISCREEN program (Taunton Energy Center, 1991c).

The proponent also conducted an evaluation of airborne pollutant concentrations on sensitive vegetation from criteria pollutants and trace elements deposited on soils. This was performed by comparing predicted facility impacts with screening levels presented in the U.S. EPA document, *A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils and Animals* (U.S. EPA, 1980). Most of the designated vegetation screening levels are equal to or greater than the NAAQS and PSD increments. Because projected emissions from the proposed project did not exceed any NAAQSs or PSD standards, no significant adverse impacts were indicated. SO_2 screening levels, for the 3-hour and annual averaging periods, are lower than the NAAQS, requiring supplemental analysis by the applicant. This analysis indicated that predicted SO_2 levels were still well below the applicable screening levels for adverse effects (Taurton Energy Center, 1991c). The applicant also conducted additional assessments to evaluate project trace element concentrations to EPA-recommended soil equivalent levels and assumed background levels; these assessments indicated impacts below recommended screening levels, and minimal predicted increases in background soils concentrations (Taunton Energy Center, 1991c).

In response to EPA comments on the Draft Environmental Impact Report, the proponent also completed supplemental analyses of (a) potential acid fog impacts resulting from the facility; and (b) a cooling tower plume impact (fogging) assessment (Taunton Energy Center, 1991d). The results of the acid fog impact analysis, which utilized a methodology developed by the New York Department of Environmental Conservation (NYSDEC) for deposition impact assessment, indicated that predicted sulfate deposition rates were below the NYSDEC environmental threshold value above which significant effects have been reported. The cooling tower impact analysis indicated that most fogging and icing will occur within TMLP boundaries, although limited fogging may occur (3-5 hours per year) to the west and northwest of the site, along Route 138. These fogging and icing conditions would likely occur during conditions of existing snow, fog, and rain events. The proponent's analysis indicated that minimal impacts to public roadways from icing are expected, and deposition of natural salts within the cooling tower plume is expected to remain below levels found to injure sensitive vegetative species (Taunton Energy Center, 1991d). As a result of the relocation of the cooling towers to the east of the facility (away from public roadways), the existing TMLP-owned buffer area to the north and west of the facility, and the limited duration of suitable meteorological conditions encouraging icing, potential icing impacts to public roadways are not expected to be significant.

6.13 Noise

Noise Limits

DEP regulates noise emissions and impacts by a policy limiting new sources to 10 dBA over the L_{90} ambient level. Pure tones, defined as any octave band level which exceeds the adjacent octave band levels by 3 dBA or more, are also not allowed (Massachusetts DEP, 1990).

Construction Impacts

Construction of the Taunton Energy Center will take about three years. On the basis of published data on the noise produced by typical construction machinery, construction noise levels are expected to range from 60 to 71 dBA at the nearest residences during the daytime. At more distant locations, the noise from construction will be in the range of 54 to 65 dBA because sound level decreases with distance from the source of the sound. Construction noise will be intermittent and temporary. Steam blows following the construction are necessary to clean out boilers and steam lines. Steam blows have acoustic power levels ranging up to about 170 dBA (Barnes, et. al, 1977), causing on the order of 100 dBA at a distance of 1000 feet from the plant. Although steam blows would occur for brief periods a few times during plant startup, this noise can be reduced by 20 dBA through the use of mufflers.

Operation Impacts

The major potential noise sources at the Taunton Energy Center can be divided into two categories; continuous noise sources, and daytime noise sources. Continuous noise sources include the induced draft fan exhaust, the induced draft fan housings and breeching, the cooling tower, the main transformer, the coal crusher building, the turbine/boiler building, the ventilation openings, and the exhaust fan. Estimates of noise from each of these sources are presented in the Prevention of Significant Deterioration (PSD)/Air Plans Application (Taunton Energy Center, 1991c). Daytime noise sources include coal unloading, the car moving mechanism, idling locomotives, limestone unloading, and ash pellet loading. Estimates of noise from these sources are also presented in the PSD/Air Plans Application.

In addition, intermittent and infrequent steam ventings will occur during routine operation. These steam releases are smaller and less noisy than the initial construction steam blows.

The weekly arrival and departure of the coal train will produce noise at locations in the vicinity of the track. The weekly train passage by residences such as the Somerset Garden Apartments is expected to result in peak noise levels of 84 dBA (due to locomotive passage). While the short duration and number of these train passages (one round trip per week) indicate that no significant impacts will result, the proponent will be required to notify affected residents of the train schedule, monitor noise impacts, and ensure use of proposed quiet locomotives to reduce these effects. The proponent has also agreed to restrict idling locomotives to an area approximately 1000 feet north of Baker Road (3500 feet south of the apartment complex) in order to reduce the potential impacts of train noise (Taunton Energy Center, 1992a). Noise from interstate railroad activities is also limited by federal regulations (40 CFR 201). The noise from the coal train is expected to be much less than would be permitted under federal regulations because of the use of quiet SD-40 locomotives and because of the slow speed of the train (Taunton Energy Center, 1991b).

Based upon ambient noise measurements taken at the monitoring sites, the DEP Noise Policy establishes the following limiting noise levels (expressed as L_{90} levels) at representative locations:

	Residential Locations	Nighttime (dBA L_{90})	Daytime (dBA L_{90})
1.	Railroad Avenue	41	47
2.	Route 138	45	53
3.	Boylston at Sunhill	43	51
4.	Baker Road	42	51

6.	Berkley Street	44	48
9.	End of Railroad Avenue	38	52
13.	Townley Farms Estate	42	50
	Property Lines		
10.	South Property Line	45	52
11.	1410 Somerset Avenue (west line)	49	54
12.	Blake Cemetery (north line)	47	49
15.	Taunton River (east line)	46	51

These limits are used to assess the potential significance of project-related noise on surrounding receptors, as well as the need for and locations of noise mitigation measures.

The cumulative impacts of all facility noise sources (e.g. fans, blowers, conveyors, coal train operations, and cooling towers) have been factored into the noise modeling conducted for the project. The modeling has also incorporated the height and directionality of expected noise sources, relative to receptor locations (Raczynski, personal communication, 1992). The results of this modeling are provided in Table 6-8.

The model results indicate that the DEP noise policy will be met by the project at all residential and property line receptors, although the maximum allowable increase of 10 dBA is expected to occur at (a) a residence at Railroad Avenue (Receptor 1) on one day per week during coal train unloading operations, and (b) the Taunton River (Receptor 10) at night and during coal unloading operations.

As a result of projected noise impacts on Receptor 1 at Railroad Avenue (which were at the DEP policy level of 10 dBA), the proponent was required to utilize a 40 to 60 foot earthen berm as part of the final grading plan to provide suitable noise attenuation. The effectiveness of this berm varies with certain atmospheric conditions. During nine months of the year, including all summer months, the berm will provide a reduction of at least 6 dBA, resulting in a 4 dBA maximum increase at Receptor 1 (assuming clear and calm conditions). This berm is expected to be least effective during February, when prevailing wind conditions may not provide any attenuation effects, and during temperature inversions. (Silver City Energy, 1991c). In addition, 9 dBA increases in noise levels are reached at Baker Road (Receptor 4) during the day, and at the end of Railroad Avenue (Receptor 9) during the night. (Taunton Energy Center, 1992a). Figures 6-3 and 6-4 show predicted maximum noise isopleths (contours of equal noise levels) during plant operation. These figures graphically illustrate areas where the DEP policy level of 10 dBA is reached or exceeded. (HMM Associates, 1992d).

Table 6-8.

SUMMARY OF NOISE LEVELS AND COMPLIANCE WITH MDEP REQUIREMENTS DURING NORMAL OPERATION, IN dBA

Position	Present Min L_{90} Amb		Predicted from TEC L_{eq}			Predicted Combined With Min L_{90}			Increases Over Min L_{90}		
	Night	Day	Night	1 Day††	6 Days	Night	1 Day††	6 Days	Night	1 Day††	6 Days
Residential Locations											
1	31	37	34† (≤40)	47	34† (≤40)	36† (≤41)	47	39† (≤42)	5† (≤10)	10	2† (≤5)
2	35	43	40	45	40	41	47	45	6	4	2
3	33	41	35	42	35	37	45	42	4	4	1
4	32	41	<35**	49	<35**	<37**	50	<42**	<5**	9	<1**
6	34	38	32	38	32	36	41	39	2	3	1
9	28	42	36	45	36	37	47	43	9	5	1
13 (New Houses East)	32	40	38	44	38	39	45	42	7	5	2
Property Line Locations											
10 (South P/L)	35	42	37*	47	37*	39*	48	43*	4*	6	1*
11 (New West P/L)	39	44	41	46	41	43	48	46	4	4	2
12 (North P/L - Cem)	37	39	40	46	40	42	47	43	5	8	4
15 (East P/L - River)	36	41	45	51	45	46	51	46	10	10	5

†† Assumes coal unloading and ash pellet loading, which are expected to happen only one day per week during the work week.

† Includes the noise reduction benefit of the earth berm, which is expected to occur at least 75% of the time. Levels in parentheses are indicative of the noise reduction benefit the remainder of the time when meteorological conditions may reduce the effectiveness of the berm.

** Noise levels at Position 4 will be less than the levels at Position 3 during the nighttime and six days per week because it is further from TEC than Position 3, for which predicted levels were calculated.

* Includes the benefit of earth berm at all times. This receptor is so close to the berm that weather effects will be negligible.

Source: Taunton Energy Center, 1992a. Major Comprehensive Plans Approval Application. Revised Noise Levels Assessment. Prepared by HMM Associates, January 1992.

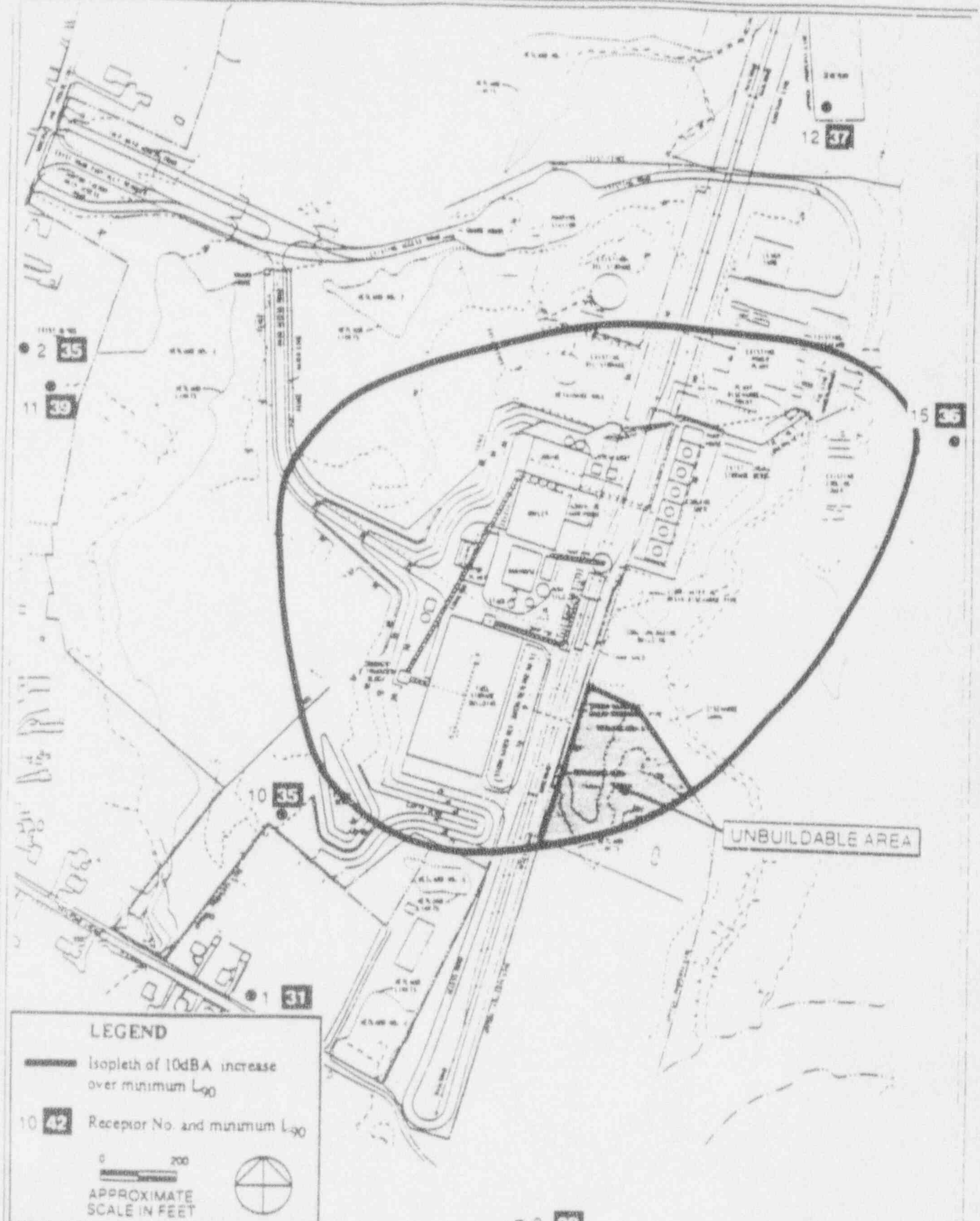

Figure 6-3
TAUNTON ENERGY CENTER SITE AND NIGHTIME TEC NOISE ISOPLETH
(10dBA Increase over minimum L_{90})

Source: HMM Associates, 1992d. Letter to Vaughan Steeves, Massachusetts Department of Environmental Protection, in reference to DEP Request on Revised Noise Levels Assessment dated January, 1992. Letter dated June 10, 1992.

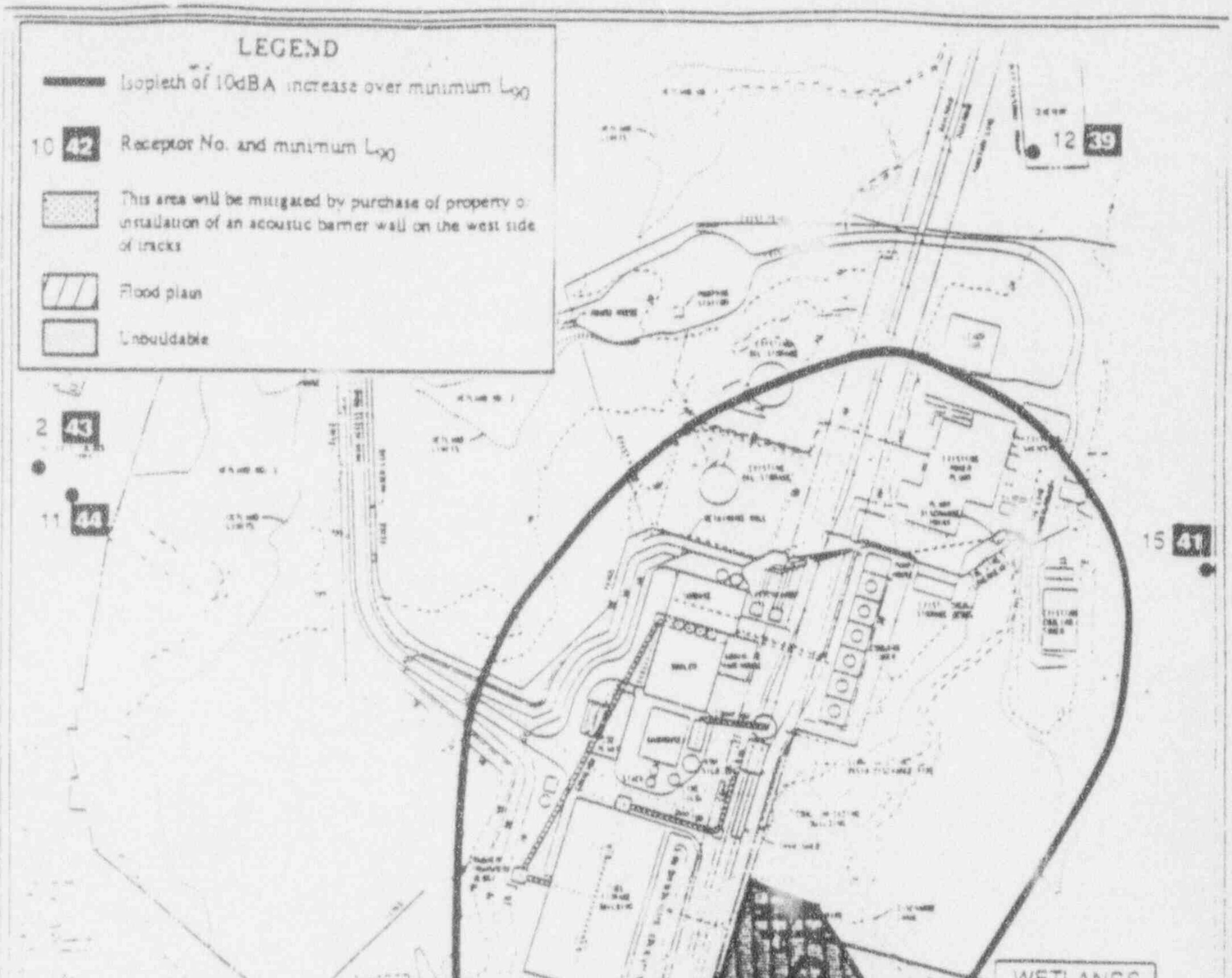

Figure 6-4
TAUNTON ENERGY CENTER SITE AND 1 DAY/WK TEC NOISE ISOPLETH
(10dBA Increase over minimum L_{90})

Source: HMM Associates, 1992d. Letter to Vaughan Steeves, Massachusetts Department of Environmental Protection, in reference to DEP Request on Revised Noise Levels Assessment dated January, 1992. Letter dated

These values indicate a moderate increase in noise from the plant at these locations, even though applicable state criteria are not exceeded, and all of the predicted increases are below the EPA-recommended outdoor residential exposure level of 55 dBA (expressed as a day-night equivalent, or L_{DN})(U.S. EPA, 1974). The monitoring data show that much of the surrounding land area is not presently subjected to high noise levels, requiring that the proponent develop and implement aggressive noise management procedures and state-of-the art noise attenuation features as part of the final facility design in order to avoid significant impacts. Figures 6-3 and 6-4 indicate that the proponent will be required to (a) purchase adjacent properties; (b) construct an earthen berm south of the coal storage building; and (c) ensure that other TMLP-properties are not developed for residential or other noise-sensitive land uses, in order to comply with the DEP noise policy. These measures, combined with the requirement for ongoing monitoring of operational noise levels (see Section 7.13), are expected to reduce potential noise impacts below significance levels.

7.0 MITIGATION MEASURES

Included as part of the proposed action are a number of project features designed to avoid or minimize potential environmental impacts during construction and operation of the facility. The mitigation measures proposed by the project proponent are summarized below. EPA expects that all environmentally-protective features incorporated by the applicant in the Draft and Final EIRs will be implemented.

Bechtel Power Corporation, a partner in Silver City Energy LP, will be contractually required under the Order of Conditions issued by the Taunton Conservation Commission to engage an environmental engineer during construction to ensure that all permit conditions, regulatory requirements, and mitigation commitments are observed. Following construction, Constellation Operating Services Company, the partner in the Silver City Energy LP which will operate the Taunton Energy Center, will have a staff Safety and Environmental Compliance Engineer who will be responsible for ensuring that all permit conditions, regulatory requirements, and mitigation commitments are observed.

7.1 Land Use

It is not expected that there will be any changes in on-site or adjacent land use associated with the proposed Taunton Energy Center facility and a number of conditions were imposed on the proponent by the City of Taunton in order to ensure that surrounding land uses are not significantly impacted. These are discussed below under Visual Resources, Rail, and Noise impact mitigation sections.

7.2 Stormwater Management

The stormwater management plan was prepared at an early stage in project planning for the purpose of mitigating the impacts from changes in stormwater flows and runoff resulting from the newly constructed facility. The maintenance of the detention basin and the monitoring of flows will ensure that the basin continues to operate as designed.

7.3 Taunton River

7.3.1 Taunton River Flows

Impacts to Taunton River flows from the proposed Taunton Energy Center are expected to be minimal. The proposed facility design is based on the reuse and recycling of water within various plant systems to the maximum extent possible. Boiler blowdown and water from plant drains will be reused in the plant as makeup water. The process wastewater discharge stream will be used in the ash pelletizing process. It is expected that all of the export steam will be returned to the facility as condensate. The reuse of returned condensate within the plant should further reduce city water consumption. Cooling water use at the facility will be minimized by operating the cooling tower at approximately five cycles of concentration, thereby reducing the makeup water requirements. Further increase in cycles of concentration is not recommended due to the complexity of the equipment required to treat the makeup water to a quality sufficient to avoid the build-up of dissolved solids and other fouling chemicals.

7.3.2 Taunton River Water Quality

Use of the existing intake and discharge structure, layout of the plant to minimize impacts to wetlands, and careful adherence to an erosion and sedimentation control plan will minimize water quality impacts during project operation. The stormwater management plan will yield continuing water quality benefits. Adherence to state and federal effluent limitations, and the required five-year renewal of the NPDES permit, will mitigate any potential impacts to water quality.

7.3.3 Taunton River Fisheries

Impacts of the project on fisheries resources are expected to be minimal. The existing intake structure has been determined to be the best available technology and presently results in minimal impacts under current operations. Impacts are expected to continue to be minimal even with the 6.5 percent additional water withdrawal.

7.4 Wetlands and Floodplain

7.4.1 Wetlands

Early identification of wetlands was incorporated into project planning so that direct impacts on wetlands could be avoided wherever possible. Although avoidance of Wetland 5 was not possible, the stormwater detention basin will be vegetated, and wetland replacement will be implemented as part of design to mitigate the wetland impacts. The proposed wetland replacement area within the stormwater basin for the disturbed Wetland 5 will take place after the construction of the plant facilities and stabilization of disturbed areas, preferably in the spring. Wetland replacement will follow the procedure presented in the Project Notice of Intent (Taunton Energy Center, 1991f).

The existing TMLP intake structure will be used to avoid construction impacts on the bank of the Taunton River or land under water bodies and the project proponent has committed to avoid wetlands impacts during the construction of over 4900 feet of sewer line. Design mitigation will be employed during the laying of the discharge pipe to minimize any alteration at the head of the discharge canal. Specific mitigation measures will also be implemented to reduce potential wetland impacts, particularly with respect to work within the 100-foot buffer zone, including soil erosion controls, sediment controls, and wetland replacement.

7.4.2 Floodplain

Mitigation for the displaced floodplain area altered during construction of the cooling tower will involve floodplain replacement, providing 1.4:1 compensatory storage volume at peak flows during the 100-year storm. The replacement area will be contiguous with the existing floodplain at elevation 14 feet. Final grading and revegetation of the floodplain replacement area will provide replacement habitat for affected wildlife.

7.5 Tidelands and the Coastal Zone

The siting of the project outside of the Coastal Zone is an avoidance mitigation measure. The facility is designed to avoid impacts to the Coastal Zone and care will be taken during cooling water withdrawal to avoid impacts to the Coastal Zone. The use of the existing intake structure and discharge canal is expected to avoid impacts on tidelands.

7.6 Rare and Endangered Species

No rare or endangered species are expected to be impacted by the project. Thus, no mitigation is proposed.

7.7 Visual Resources

The choice of a well-buffered site for the project constitutes avoidance mitigation. Layout mitigation is employed in the placement of the coal storage building so as to occlude and soften views of the more distant boiler and turbine buildings. TEC will be required to investigate and develop suitable landscaping features and facility color schemes (e.g. use of earth and sky tones), to reduce potential visual impacts from the facility. In addition, the applicant will construct earth berms at the southern end of the facility to reduce visual and noise impacts to Railroad Avenue residences, and will plant approximately two acres of Eastern white pine along the northwest property line to visually shield the facility from residences along Route 138.

7.8 Recreational Resources

The development of the Taunton Energy Center is not expected to adversely affect recreational access to the Taunton River. Nonetheless, recognizing the desirability of improved recreational access, the project proponent met with City officials to develop a plant to promote access to the river (e.g., development of a canoe landing and participation in a tree planting program).

7.9 Historic and Archaeological Resources

Because of the location of the proposed facility, no historic or archaeological resources are expected to be impacted by the proposed facility. Thus, no mitigation is proposed.

7.10 Traffic

Traffic during construction will be limited, where possible, through the use of rail to deliver construction material. However, the use of rail may not be feasible at all times because construction of the rail spur will occur concurrently with construction of the facility. To minimize use of the surrounding roadways, the arrivals and departures for the construction workers will be restricted to outside of the commuter peak hours. In addition, the project proponent has committed to provision of a traffic control officer during periods of peak construction traffic, as determined necessary by Taunton authorities to avoid any conditions of congestion. This has been incorporated as a condition of the TEC's June, 1992 Curb-cut permit issued by the Massachusetts Highway Department.

7.11 Rail

The Taunton Energy Center will guarantee unobstructed passage for trains if the rail spur extending south from the project is ever restored to use, in accordance with a commitment between the Taunton Energy Center and the Massachusetts Executive Office of Transportation and Construction (EOTC). This will be incorporated as a condition to the Operating Agreement that the project proponent must execute with EOTC in order to utilize EOTC-owned trackage to access the plant. In addition, the project proponent will be required to coordinate train arrivals and departures to minimize impacts to residences and city services (e.g. fire and police), based upon agreements reached with the city of Taunton (Taunton Municipal Council, 1991).

7.12 Air Quality

Mitigation will be implemented during construction to minimize impacts from dust. Exposed areas will be properly treated with water, calcium chloride or other approved dust-suppression agents to avoid excess emissions of particulate matter and to minimize fugitive dust.

Once the plant is operational, emissions of air pollutants from the Taunton Energy Center will be extensively mitigated by the application of Best Available Control Technology (BACT). In addition, the proposed stack height has been selected to satisfy Good Engineering Practice (GEP) criteria and will avoid the unfavorable dispersion effects of downwash which is induced by the passage of air over the boiler building. The proponent was also required by Massachusetts DEP to conduct additional fluid modeling to confirm the need for an increased stack height for the existing TMLP facility to avoid downwash. The study concluded that the existing facility would require a higher stack to reduce the potential for downwash (Cermak, Peterka Peterson, 1992). A tree-planting program is being required for Taunton and the project vicinity to offset potential increases in CO_2 from the project (Taunton Energy Center, 1991e).

The pelletized ash shall meet the requirements guaranteed by the project proponent and must be disposed of in accordance with state and federal requirements. The project proponent guarantees that the pelletized ash will be a dust-free product which does not break down during transport, and thus does not need to be covered.

7.13 Noise

The facility will be situated on a relatively well-buffered site, adjacent to an existing power facility. Where practical, buildings have been located to maximize their noise shielding effects for residences. Several components of the layout and design, including the cooling towers, have been relocated away from sensitive noise receptors to reduce potential noise impacts.

However, the projected noise impacts discussed in Section 6.13 will require the development and implementation of aggressive noise management procedures and state-of-the art noise attenuation features (e.g. mufflers and louvers for stack, cooling tower, and other fans) as part of the final facility design, in order to avoid significant impacts. The proponent will also be required to (a) purchase adjacent properties; (b) construct an earthen berm south of the coal storage building; (c) ensure that other TMLP-properties are not developed for residential or other noise-sensitive land uses; (d) notify affected residents of the proposed coal train schedule; (e) monitor train noise levels; (f) restrict the staging locations for idling locomotives to a suitable area; and (f) use quiet-running locomotives, in order to comply with the DEP noise policy.

In view of the level of impacts at Railroad Avenue and across the river, and the potential for short-term adverse impacts from construction-related noise and steam releases, the proponent will also be required to install appropriate muffling devices to the maximum extent practicable to minimize noise impacts from these releases (as a condition of the design specifications and construction contracts), and to provide advanced notice of steam releases (where feasible) in order to ensure that adjacent impacts remain below significant levels. In addition, a project noise control officer will be responsible for monitoring and addressing any excessive noise impacts (including the performance of the earthen berm south of the facility) once the facility is operational.

8.0 AGENCIES AND PERSONS CONSULTED

The following agencies and persons were contacted to obtain information on the environment in the vicinity of the project site and the potential impacts of the proposed Taunton Energy Center:

U.S. Fish & Wildlife Service, Conte Anadromous Fish Research Laboratory, Turner Falls, MA, Boyd Kynard.

National Marine Fisheries Service, Northeast Region, Gloucester, MA, Doug Beach.

Massachusetts Department of Environmental Protection, Southeast Regional Office of Air Quality Control, Lakeville, MA, Seth Pickering.

Massachusetts Department of Public Utilities, Boston, MA, Brian Abbanat.

Massachusetts Energy Facilities Siting Council, Boston, MA, Pamela Chan.

Massachusetts Historical Commission, Boston, MA, Ed Bell.

U.S. Army Corps of Engineers, New England Division, Regulatory Branch, Waltham, MA, Karen Adams.

9.0. LIST OF PREPARERS

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HMM Associates, 1992b. Letter to Vaughan Steeves, Massachusetts Department of Environmental Protection, in reference to Excessive Concentration Modeling Study prepared for Taunton Municipal Lighting Plant, May 13, 1992.

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The Commonwealth of Massachusetts

DEPARTMENT OF PUBLIC UTILITIES

October 25, 1993

D.P.U. 93-135

Investigation by the Department of Public Utilities on its own motion into the implementation of Section 712 of the Energy Policy Act of 1992.

I. INTRODUCTION

On October 24, 1992, the Energy Policy Act (Public Law 102-486) ("EPACT") was signed into law. Section 712 of EPACT (16 U.S.C. § 2621(d)(10)) directs each state public utility commission that requires or allows electric companies to consider the purchase of long-term wholesale power as a means of meeting electric demand to determine, when evaluating such purchases in the future, whether the commission will consider the following four issues associated with such purchases:

> (i) The potential for increases or decreases in the cost of capital for electric companies that make long-term wholesale power purchases and any resulting increases or decreases in retail rates that may result from purchases of long-term wholesale power in lieu of utility construction of new generation facilities.
>
> (ii) Whether the use by exempt wholesale generators ("EWGs")[1] of capital structures that employ proportionally greater amounts of debt than the capital structures of electric companies (a) threatens reliability, or (b) provides EWGs with an unfair advantage relative to electric companies.
>
> (iii) Whether to implement procedures for the advance approval or disapproval of the purchase of a particular long-term wholesale power supply.
>
> (iv) Whether to require as a condition for the approval of the purchase of such power that there be reasonable assurances of fuel supply adequacy.

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[1] An EWG is defined in Section 711 of EPACT as the owner or operator of a facility used for the generation of electric energy exclusively for sale at wholesale, or leased to one or more public utility companies, and which is exempt from the limitations regarding financing of public utilities, as stated in the Public Utility Holding Company Act of 1935.

EPACT requires that each state commission make a determination by October 23, 1993, as to whether any or all of these four issues should be considered during the review of long-term wholesale power purchases in order to carry out the following purposes of the Public Utility Regulatory Policies Act of 1978 ("PURPA"): (1) conservation of energy supplied by electric utilities; (2) optimization of the efficiency of use of facilities and resources by electric utilities; and (3) equitable rates to electric consumers. 16 U.S.C. §§ 2611, 2621(a), 2621(c), 2621(d)(10)(E).

In Massachusetts, the Integrated Resource Management ("IRM") process[2] implemented by the Department of Public Utilities ("Department") already provides for the advance approval or disapproval of long-term wholesale purchases. D.P.U. 86-36-G at 56-57 (1989); 220 C.M.R. §§ 10.03, 10.04, 10.05. In addition, the Department currently considers fuel supply adequacy as part of its review of a proposed contract for the purchase of wholesale power by electric utilities.[3] See 220 C.M.R. §§ 9.03, 10.03(10)(d)3.

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2 The IRM process involves a four-phase review. In Phase I, the Department reviews the demand forecast and resource inventory of an electric utility, makes a determination of resource need; and reviews the utility's all-resource solicitation request for proposals ("RFP"). Phase II comprises the utility's resource solicitation process, in which the utility issues the Department-approved RFP, consistent with findings on resource need. Phase III comprises the Department's review of the utility's award group, and Phase IV comprises the Department's procedure for approving contracts in the award group. See Rules to Implement Integrated Resource Management Practices, D.P.U. 89-239 (1990); 220 C.M.R. §§ 10.00 et seq.

3 Furthermore, pursuant to G.L. c. 164, §§ 69H, 69J, in the course of its review of certain proposed power plants, the Energy Facilities Siting Board has the authority to consider fuel supply adequacy as part of its project viability test. Enron Power Enterprise Corporation, 23 DOMSC 1, 89 (1991); Eastern Energy Corporation, 22 DOMSC 188, 296 (1991); West Lynn Cogeneration, 22 DOMSC 1, 64 (1991).

However, as of the date of this Order, the Department has not addressed (1) the impacts of long-term wholesale purchases on the cost of capital of electric utilities, or (2) the specific implications of the capital structure of EWGs.

Although IRM already provides for advance approval of long-term purchases and the Department is authorized to consider fuel supply adequacy, EPACT requires that state commissions formally determine whether each of the four issues presented in Section 712 will be considered in evaluating long-term wholesale power purchases. 16 U.S.C. § 2621(d)(10)(D). Accordingly, in this order the Department determines whether consideration of any or all of the four issues specified in Section 712 of EPACT would further the purposes of PURPA.[4]

II. PROCEDURAL HISTORY

On July 28, 1993, the Department opened its investigation into the implementation of Section 712 of EPACT. A Notice of Inquiry and a Notice of Public Hearing were issued inviting comments from interested persons on whether the issues set forth in Section 712 should be considered as part of the Department's review of long-term wholesale purchases of electric utilities,[5] and whether consideration of any of these issues would require any changes to the current regulatory or statutory structure.

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[4] The Department also is authorized under Massachusetts statutes to establish new rules and policies regarding long-term wholesale power purchases. G.L. c. 164, §§ 76, 76C, 94, 94A, 94B and 94G.

[5] EPACT does not require the Department to determine precisely how Section 712 issues will be evaluated if the Department determines that any or all issues should be considered.

Initial written comments were submitted to the Department by the Attorney General of the Commonwealth ("Attorney General"), Boston Edison Company ("BECo"), Com/Energy Services Company ("Com/Energy"), the Coalition of Non-Utility Generators and the National Independent Energy Producers ("CONUG & NIEP"), Eastern Edison Company and Montaup Electric Company, the Electric Generation Association ("EGA"), IRATE, Inc. ("IRATE"), Massachusetts Electric Company ("MECo"), Commonwealth of Massachusetts Division of Energy Resources ("DOER"), Massachusetts Municipal Wholesale Electric Company ("MMWEC"), Massachusetts Public Interest Research Group ("MASSPIRG"), Milford Power Limited Partnership ("Milford"), Municipal Electric Association of Massachusetts, Inc. ("MEAM"), Town of Reading Municipal Light Department ("Reading"), and Western Massachusetts Electric Company ("WMECo").

On August 24, 1993, the Department held a public hearing and received oral comments from the Attorney General, WMECo, CONUG & NIEP, Com/Energy, MECo and MASSPIRG. Written reply comments were submitted by BECo, CONUG & NIEP, MECo, Tellus Institute ("Tellus"), and WMECo.

III. Issue (i): Whether long-term wholesale power purchases increase or decrease the cost of capital for the purchasing electric utilities

A. Positions of the Parties

The electric utilities provide a consistent response to the issue of cost of capital increases, arguing that purchased-power contracts can increase the purchasing utility's cost of capital by increasing its payment obligations (BECo Comments at 2; Com/Energy Comments at 3; MECo Comments at 3; WMECo Comments at 7). The utilities contend that bond-rating agencies view long-term purchase power contracts as debt-like obligations (or "off-balance sheet debt"), and when the debt equivalent of contracts is added to the pre-existing debt, debt ratios of utilities increase and interest coverage ratios decrease (Com/Energy Comments at 3; MECo Comments at 4). Bond-rating agencies and equity investors use the foregoing ratios, as well as other criteria, to determine the level of investment risk represented by an electric utility (MECo Comments at 4-5). Accordingly, the electric utilities argue, if bond-rating agencies view purchased-power contracts as an addition to risk, a utility's cost of financing will be higher to the extent that it relies on purchased power (Com/Energy Comments at 6; WMECo Comments at 8). The electric utilities also assert that bond-rating agencies downgraded the ratings of certain utilities, including BECo and the Southern California Edison Company, due in part to the amount of purchased-power contracts signed by such utilities (BECo Comments at 1-2; WMECo Comments at 6; Tr. 1, at 102 (Com/Energy)).

However, the electric utilities also acknowledge that the level of risk attributable to long-term power purchases can be mitigated by certain contract provisions (MECo Comments at 6; WMECo Comments at 15; BECo Comments at 3; Tr. 1, 116-117 (Com/Energy)). For example, "flexible" contracts that exhibit features such as dispatchability, pay-for-performance clauses, and buy-out provisions reduce utility risk because the foregoing provisions provide utilities with the ability to respond to changes in the economy or power needs (id.). Nonetheless, the utilities argue that power purchases can still present some risk, and therefore, the Department should consider the effects of purchased power on a utility's cost of capital in the IRM process (MECo Comments at 6). MECo recommends that the

Department award utilities a margin on contracts for long-term wholesale purchased power to compensate the utility for its increased financial risk, encourage sound contract development, and eliminate the present ratemaking disincentives to purchased-power contracts (MECo Comments at 7).

CONUG & NIEP, EGA, and Milford ("NUG Parties") argue that power purchase obligations pose no increase in risk, but on the contrary, lower risk for purchasing utilities, and that no special consideration of utilities' cost of capital is warranted (CONUG & NIEP Comments at 3; EGA Comments at 2-3; Milford Comments at 4). The NUG Parties contend that capacity payments for purchased power generally are paid conditionally, i.e., only if a long list of specific performance requirements are met, as compared to debt payments which must be met unconditionally (CONUG & NIEP Comments at 3). The NUG Parties also maintain that since capacity payments are "pass-throughs" to ratepayers, they have little or no effect on a utility's cost of capital (CONUG & NIEP Comments at 3; EGA Comments at 2). CONUG & NIEP argue that rather than making explicit compensation for any alleged risk in a electric utility's resource solicitation scoring system, utilities should be rewarded on the basis of their success in purchasing least-cost power from the marketplace of competitive generators (Tr. 1, at 60-62). CONUG & NIEP also assert that IRM already requires consideration of all costs and benefits of all resource options when selecting the least-cost resource mix (CONUG & NIEP Reply Comments at 2).

The Attorney General and IRATE argue that the Department should consider effects on a utility's cost of capital within the IRM process (Attorney General Comments at 3; IRATE Comments at 3). The Attorney General also argues that contemplation of this matter is already within the scope of IRM and "leads to increased efficiency in both utilities' and society's resources, and, in this way, to equitable rates," a goal of PURPA in accordance with Section 712 of EPACT (Attorney General Comments at 3).

DOER recommends that the Department not institute any changes at this time to the methodology or process used to evaluate long-term wholesale power purchases (DOER Comments at 1). DOER maintains that impacts on a utility's cost of capital from long-term wholesale power purchases do not necessitate any immediate action by the Department, and that a response now could be premature since the base of knowledge regarding this issue continues to expand (id.).

MASSPIRG argues that the risks to utilities represented by Section 712 of EPACT must be evaluated as part of a broad spectrum of risks which encompasses purchased-power contracts in general as well as project-specific characteristics, all in terms of comparisons with other options available to the utility (MASSPIRG Comments at 1). MASSPIRG also notes that utilities assume none of the risk associated with ensuring that fixed payments to power suppliers are made because under Massachusetts regulation those risks are explicitly assigned to utility ratepayers, i.e., all purchased-power costs flow straight through to the ratepayer (Tr. 1, at 166-167).

Tellus states that credit rating agencies have recently acknowledged that there is no risk-free way for an electric utility to add new capacity, whether it be through long-term, wholesale purchased-power contracts or by constructing new capacity (Tellus Comments at 4). Tellus argues that any proposal by an electric utility to discount the value of purchased power or increase its return on equity in order to compensate for increased risk should be considered in light of the risks of the utility constructing its own facility, as well as all risk-allocation contract provisions available (id.). Tellus also maintains that an evaluation of utility cost of capital is irrelevant to the purposes of PURPA (id.).

Municipal electric utility commenters argue that the instant proceeding does not apply to non-regulated electric utilities such as municipal electric systems (MMWEC Comments at 1; MEAM Comments at 1; Reading Comments at 2). Reading further claims that municipal electric utilities are authorized to implement the standards in PURPA at 16 U.S.C. § 2621 as independent entities (Reading Comments at 3).

B. Analysis and Findings

A major objective of IRM is to "determine the mix of resources that is most likely to result in a reliable supply of electrical service at the lowest total cost to society." 220 C.M.R. § 10.04(1). Specifically, IRM requires consideration of all costs and benefits of all resource options in order to identify the least-cost resource mix. See 220 C.M.R. § 10.03(10); D.P.U. 86-36-G at 31. To that end, and consistent with the arguments of the Attorney General and CONUG & NIEP, the Department finds that the consideration of the effect of a long-term wholesale power purchase, or of any other resource option, on a utility's cost of capital is implicitly contemplated within the IRM process.

The Department also finds that consideration of measurable cost of capital effects as well as all other costs and benefits of resource options within the IRM process may enhance an electric utility's ability to select the least-cost resource mix, and thus, provide more "equitable rates for its customers." In addition, the Department finds that the consideration of any measurable effect of a resource option on a utility's cost of capital may increase the cost-effectiveness of demand-side programs relative to supply-side options and thus promote the "conservation of energy supplied by electric utilities." Therefore, in accordance with Section 712 of EPACT, the Department finds that consideration of measurable cost of capital effects due to a specific resource option is consistent with two of the three purposes of PURPA.

Although the Department finds no justification in the record for bond-rating agencies to downgrade utility bonds due to the purchase of long-term wholesale power, we cannot ignore the fact that some bond-rating agencies have used such purchases as a partial rationale for utility bond downgrades, or ignore the impact that such downgrades may have on electric utility rates. However, the Department finds that the record provides no clear indication of whether, or to what extent, future wholesale power purchases will positively or negatively affect an electric utility's cost of capital. Therefore, the Department will make no such determination at this time. Rather, the Department finds that it is appropriate to consider this issue on a case-by-case basis within the context of individual electric utility IRM proceedings.

Further, the Department finds that, should any party elect to pursue this issue in an IRM proceeding, it must provide sufficient evidence and quantify any such effects on the affected utility's cost of capital that is attributable to a resource option in order for the Department to consider any such effects. Specifically, the Department finds that an electric utility claiming positive or negative effects on its cost of capital due to a resource option must provide a comprehensive assessment of its current and future financial condition, including all significant purchased power and non-purchased power components, and an assessment of the relative impacts that all potential resource options and all risk-mitigating contract provisions may have on the utility's financial condition. In addition, an electric utility must fully address any and all mechanisms which are likely to alleviate any negative effects.

Regarding the arguments put forth by municipal electric utility commenters, the Department concurs that this investigation is not applicable to non-regulated electric utilities including municipal electric utilities. 16 U.S.C. § 2621(d)(10). Accordingly, the Department notes that the findings made in this Order do not apply to the municipal electric utilities.

IV. Issue (ii): Whether the employment by EWGs of proportionally greater amounts of debt than is employed by electric utilities (a) threatens reliability, or (b) provides the EWGs with an unfair advantage relative to electric utilities.

A. Positions of the Parties

MECo argues that the capital structure available to EWGs should not affect reliability (MECo Comments at 8). In addition, MECo notes that reliability is already considered within the IRM process (id.). MECo contends that there is no unfair advantage associated with the capital structure available to EWGs (id.). MECo asserts that to the extent an EWG lowers its costs through higher proportions of debt, "this situation produces savings, it is fair, equitable, and should be encouraged" (id.). MECo maintains that any increased risk due to the capital structure available to EWGs is already addressed in the contracting process, and thus, it is not necessary for the Department to take any further action on this issue (Tr. 1, at 134). MECo states that it opposes the use of any equity contribution scoring adder in IRM because "mechanistic" formulas do not provide sufficient flexibility for utility management (id., at 138-139).

BECo states that supply-system reliability represents a major concern for electric utilities, but adds that reliability concerns can be minimized by appropriate contract provisions (BECo Comments at 3). BECo does not claim that reliability is affected by the financing capabilities of EWGs (id.). BECo argues that as long as the solicitation process remains open to all participants, including utilities, there is no unfair advantage inherent in the capital structures available to EWGs (id.).

WMECo argues that the higher proportions of debt available to EWGs threaten reliability to the purchasing electric utility system (Tr. 1, at 23-24). WMECo maintains that because of the high debt/equity ratios available to EWGs, electric utilities are at a competitive disadvantage when compared to an EWG, although WMECo acknowledges that it has the ability to develop an EWG through a corporate subsidiary (WMECo Comments at 9; Tr. 1, at 37).

WMECo also proposes several modifications and additions to existing processes. Specifically, WMECo recommends that the Department require resource bidders to provide full disclosure of financial information when participating in preapproval or contracting processes (id. at 10). WMECo further proposes the establishment of an "equity contribution" category in the IRM process in order to establish a "level playing field," i.e., to mitigate any competitive advantage over utility-built projects (id. at 8-10). WMECo also contends that the IRM process should be streamlined to substantially reduce time and effort by utilities, regulators, and other interested parties (id. at 12).

Com/Energy argues that increased leverage can increase a project's likelihood of failure, but also admits that it has "found existing [non-utility generating] facilities to be as reliable as utility-owned facilities and ha[s] no reason to assume that EWGs will be any less reliable" than non-utility generators have been historically (Com/Energy Comments at 7; Tr. 1, at 104). Com/Energy states that purchased-power contracts can incorporate protections specifically designed to minimize adverse effects on system reliability in the event of project failure (Com/Energy Comments at 8). Com/Energy notes, however, that its contractual protections are as yet untested in court, and therefore urges the Department to "exercise caution in any policy it might adopt concerning consideration of the proper level of leverage for a wholesale seller of power" (id.). Com/Energy states that, in evaluating power supply options, it seeks low-cost electricity and contract flexibility, thereby minimizing cost and risk to its customers (Tr. 1, at 127-128). Regarding the question of unfair advantage due to EWG capital structure, Com/Energy concludes that EWGs have no such advantage (Tr. 1, at 128).

The NUG Parties argue that the capitalization of EWGs has no impact on the reliability of power supply and provides no unfair advantage over electric utilities (Milford Comments at 6; EGA Comments 10-12; CONUG & NIEP Comments at 7). Milford notes that a study of 122 cogeneration units yielded an availability factor of 90 to 96 percent compared to that of 86 percent for utility-owned generation (Milford Comments at 7). The NUG Parties maintain that the capitalization structures available to EWGs are unrelated to operational factors, including reliability associated with non-utility generating facilities (Milford Comments at 6; EGA Comments at 12; CONUG & NIEP Comments at 8). The

NUG Parties also contend that the same financing available to EWGs is equally available to utilities, and therefore presents no advantage, unfair or not, to EWGs (CONUG & NIEP Comments at 7; EGA Comments at 10).

The Attorney General argues that the Department's IRM process already contemplates the reliability of proposed resources (Attorney General Comments at 4). The Attorney General also states that if an unfair advantage associated with higher leverage available to EWGs leads to selection of a resource that is not least-cost, that would result in "inequitable rates," and thus the Department should determine that it will consider the issue in its evaluations of wholesale power purchases (id. at 4-5).

Tellus argues that the capital structure employed by EWGs does not result in reduced reliability (id. at 9). Tellus maintains that the investors in a non-utility project evaluate the project for all major risks, and that the NUG industry has matured considerably, now including companies with proven track records of reliability (id. at 8-9). Tellus contends that to the extent that EWGs do have an advantage over utility generation, it is not due to the cost of capital available to it, but from other business and operating risk factors. (id. at 10). Tellus contends that "if this advantage can be captured by an EWG, it is simply the result of competition to the ratepayers' benefit" (id. at 11).

B. Analysis and Findings

The Department notes that, as the Attorney General contends, the IRM process specifically contemplates an evaluation of the reliability of proposed resources, and that adequate security to protect ratepayers from uncertainties associated with all resource options is required in that process. The Department further notes that electric utilities have the option to develop and propose their own EWG projects through subsidiaries, which may utilize any and all financing options available to EWGs.

Further, the Department finds that no convincing documentation was presented of any correlation between the capital structures available to EWGs and the reliability of such facilities. The Department also finds that no convincing documentation was presented of any unfair advantage associated with the capital structures available to EWGs. However, the Department is reluctant to preclude prospectively the presentation of evidence relevant to a future proceeding. Additionally, in accordance with Section 712 of EPACT, the Department finds that consideration of the reliability and competitive advantage aspects of EWGs due to their capital structure may be consistent with the third purpose of PURPA, i.e., provision of equitable rates to electric consumers. Therefore, the Department will allow electric utilities to present during IRM proceedings evidence that demonstrates that the employment by EWGs of proportionally greater amounts of debt than is employed by electric utilities either threatens reliability or provides the EWGs with an unfair advantage relative to electric utilities.

Regarding changes to the IRM process and economic incentives proposed in this proceeding, the Department finds that such comments are beyond the scope of this proceeding, and thus will not be addressed in this Order.

V. ORDER

Accordingly, after due consideration, it is

ORDERED: That when evaluating long-term wholesale power purchases, the Department will continue to preapprove or disapprove of such purchases, as appropriate; and it is

<u>FURTHER ORDERED</u>: That when evaluating long-term wholesale power purchases, the Department will continue to consider fuel supply adequacy in accordance with 220 C.M.R. §§ 9.03, 10.03(10)(d)3; and it is

<u>FURTHER ORDERED</u>: That when evaluating long-term wholesale power purchases, the Department will consider evidence that demonstrates that such purchases would increase or decrease the utility's cost of capital; provided, however, that any party offering such evidence shall have the burden of establishing the existence of any impact on the cost of capital and of sufficiently quantifying that impact; and it is

<u>FURTHER ORDERED</u>: That when evaluating long-term wholesale power purchases within the current review process, the Department will consider evidence that demonstrates that the employment by EWGs of proportionally greater amounts of debt than is employed by electric utilities threatens reliability or provides the EWGs with an unfair advantage relative to electric utilities; provided, however, that any party offering such evidence shall have the burden of establishing any such threat to reliability and any such unfair advantage.

By Order of the Department,

/s/ KENNETH GORDON

Kenneth Gordon, Chairman

A true copy
Attest;

Mary L. Cottrell

MARY L. COTTRELL
Secretary

221

THE COMMONWEALTH OF MASSACHUSETTS

Office of the Secretary of State

Regulation Filing *To be completed by filing agency*

CHAPTER NUMBER: 220 C.M.R. 10.00

CHAPTER TITLE: Rules Governing the Procedure by which Additional Resources are Planned, Solicited and Procurred by Investor-Owned Electric Companies.

AGENCY: Department of Public Utilities

SUMMARY OF REGULATION

State the general requirements and purposes of this regulation:

Procedures by which Investor-Owned Electric Companies provide the DPU with their analysis of future electricity needs and plans for acquiring and providing for the identified need.

REGULATORY AUTHORITY: G.L. c. 164, §§ 76, 94,94B and 96G

AGENCY CONTACT: Robert Shapiro, Esq. PHONE: 727-3500

ADDRESS: General Counsel 100 Cambridge St., Boston,MA 02202

Compliance with M.G.L. c. 30A

EMERGENCY ADOPTION

If this regulation is adopted as an emergency regulation, state the nature of the emergency. Chapter 141 of the Acts of 1992 transfers jurisdiction over the affected procedure from the energy Facilities Siting Council to the Department of Public Utilities effective September 1, 1992.

PRIOR NOTIFICATION AND/OR APPROVAL

If prior notification to and/or approval of the Governor, legislature or others was required, list each notification, approval and date, including notice to the Local Government Advisory Commission:

Notice to Massachusetts Municipal Association mailed August 21, 1992.
Notice to Department of Community Affairs mailed August 21,1992.

PUBLIC REVIEW

Was notice of the bearing or comment period filed with the Secretary of State published in appropriate newspapers and sent to persons to whom specific notice must be given at least 21 days prior to such bearing or comment period?

Yes [X] Date of public hearing or comment period: Hearing October 9,1992
Comments October 16, 1992

FISCAL EFFECT

Estimate the fiscal effect on the public and private sectors:

For the first and second years:

For the first five years:

No fiscal effect: Regulations already exist, just consolidating into one chapter.

SMALL BUSINESS IMPACT

State the impact of this regulation on small business. Include a description of reporting, record keeping and other compliance requirements as well as the appropriateness of performance versus design standards and whether this regulation duplicates or conflicts with any other regulation. If the purpose of this regulation is to set rates for the state this section does not apply.

No impact

CODE OF MASSACHUSETTS REGULATIONS INDEX

List key subjects entries that are relevant to this regulation:

PROMULGATION

State the action taken by this regulation and its effect on existing provisions of the Code of Massachusetts Regulations (CMR) to repeal, replace or amend. List by CMR number:

Amends 220 C.M.R. 10.00

ATTESTATION

The regulation described herein and attached hereto is a true copy of the regulation adopted by this agency. (ATTEST)

Signature: Mary L. Cottrell Date: December 4,1992

MARY L. COTTRELL, SECRETARY

Publication *To be completed by the Regulations Division*

MASSACHUSETTS REGISTER NUMBER: 702 DATE: 12/18/92

EFFECTIVE DATE: 12/18/92

CODE OF MASSACHUSETTS REGULATIONS

Remove these pages: CMR: Vol.	*Insert these pages:*
1, 2 81-98	1, 2 81-98.8

A TRUE COPY ATTEST

Michael Joseph Connolly

MICHAEL JOSEPH CONNOLLY

SECRETARY OF STATE

DATE 12/4/92 CLERK

Table of Contents

Table of Contents (continued)

220 CMR 10.00: RULES GOVERNING THE PROCEDURE BY WHICH ADDITIONAL RESOURCES ARE PLANNED, SOLICITED, AND PROCURED BY INVESTOR-OWNED ELECTRIC COMPANIES

Section

10.01: Purpose and Scope

(1) Purpose. The purpose of 220 CMR 10.00 is to establish procedures by which additional resources are planned, solicited and procured to meet an investor-owned electric company's obligation to provide reliable electrical service to ratepayers at the lowest total cost to society. 220 CMR 10.00 establishes the procedure for determining the need for additional resources. 220 CMR 10.00 also establishes the level of costs for additional resources that is proper, just, reasonable, required by the public interest, and recoverable through retail rates charged to customers of electric companies.

(2) Scope.
(a) 220 CMR 10.00 applies to: forecasts of electricity demand and supply; evaluations of resource need and potential; requests for resource proposals; solicitations and evaluations of alternate project proposals; and plans to meet additional resource requirements as they apply to the rates, terms, and conditions of contracts between resource suppliers and electric companies. 220 CMR 10.00 also applies to the rates, terms, and conditions for the recovery by electric companies of the costs of their own additional investment in electrical service resources.
(b) Affected utilities. 220 CMR 10.00 applies to the following investor-owned electric companies:

1. Boston Edison Company
2. Cambridge Electric Light Company
3. Commonwealth Electric Company
4. Eastern Edison Company
5. Fitchburg Gas and Electric Light Company
6. Massachusetts Electric Company
7. Montaup Electric Company
8. New England Power Company
9. Northeast Utilities
10. Western Massachusetts Electric Company

(c) Upon the implementation date of 220 CMR 10.00 for each affected utility, 220 CMR 8.05 shall have no force or effect.

10.02: Definitions

The terms set forth below shall be defined as follows in 220 CMR 10.00, unless the context otherwise requires.

All-Resource Solicitation shall mean the process by which electric companies solicit and evaluate supply-side and demand-side resources from project developers, as described in 220 CMR 10.04.

Award Group shall mean the group of project proposals from the all-resource solicitation that is selected for final contract negotiation and signing, or, in the case of electric company project proposals, for pre-approval pursuant to 220 CMR 9.00. The project proposals in the award group shall be presented to the Department for approval as part of the electric company's proposed resource plan.

Base Case Scenario shall mean the electric company's most likely demand forecast scenario.

10.02 continued

Conservation shall mean a technology, measure, or action designed to decrease the kilowatt or kilowatt-hour requirements of an electric company.

Cream-Skimming shall mean the act of installing only those C&LM measures with the highest rate of return in a given situation or location without capturing all other cost-effective C&LM. Cream-skimming often results in lost C&LM opportunities, since it is typically uneconomic to return to the end-user's premises to install the remaining C&LM measures that would have been cost-effective had they been installed as a package with the other installed C&LM measures.

Customer shall mean any entity purchasing electricity from the host electric company on a retail basis.

Demand-Side Resource or DSM shall mean any conservation or load management technology, measure, or action.

Department shall mean the Department of Public Utilities.

Draft Initial Filing shall mean the preliminary initial filing proposed by the host electric company for the purposes of pre-filing settlement discussions, pursuant to 220 CMR 10.03(4). The draft initial filing shall be sufficiently complete to support meaningful discussion of the issues. If agreement is reached on any of the components of the draft initial filing, those components can be submitted as part of the company's initial filing.

Electric Company shall mean those affected utilities listed in 220 CMR 10.01(2)(b).

Environmental Externalities shall mean the value of those environmental damages (or impacts) caused by a project or activity for which compensation to affected parties does not occur, regardless of whether the damages are imposed within Massachusetts' borders or elsewhere.

Existing DSM Resource shall mean a resource that decreases the kilowatt or kilowatt-hour requirements of an electric company or that modifies the time pattern of customer capacity or energy requirements, and that has been installed at least one month prior to the date of the initial filing.

Existing Supply-Side Resource shall mean a supply-side resource that either (a) has been providing kilowatts or kilowatt-hours to the electric company at some time within the year beginning 13 months before and ending one month before the submission of the initial filing, or (b) has provided kilowatts or kilowatt-hours to the electric company at some time other than 13 months before the submission of the initial filing and can be made operational without approval from the Department.

Fuel Switching shall mean a measure or action designed to decrease the kilowatt or kilowatt-hour requirements of an electric company through the use of alternative fuels or technologies to meet the requirements of an end-use.

Host Electric Company shall mean the electric company that conducts the all-resource solicitation for the purpose of procuring resources.

Initial Filing shall mean the documents filed by the host electric company at the Department at the beginning of Phase I. The initial filing shall include all of the documents described in 220 CMR 10.03(2)(b).

Initial Resource Portfolio shall mean the combination of resources proposed by the host electric company in the initial filing, pursuant to 220 CMR 10.03(5). The initial resource portfolio shall contain, at a minimum, the additional resources proposed to meet the incremental resource need identified by the company in the initial filing at the lowest total cost to society. The initial resource portfolio may include existing resources, with or without proposed modifications, that the company wishes to subject to competitive ranking. The projects proposed in the initial resource portfolio shall be compared with project

10.02: continued

proposals submitted by other parties in the all-resource solicitation. The information regarding the initial resource portfolio provided in the initial filing need not include price, method of cost recovery, or other cost information.

Life Extension shall mean a specific program implemented in connection with an existing supply-side resource where such a program extends the retirement date of the existing supply-side resource.

Load Management shall mean a measure or action designed to modify the time pattern of customer capacity or energy requirements, for the purpose of improving the efficiency of the electric company's operating system.

Long-Run Standard Contract A shall mean a standard contract that the host electric company shall make available to all project developers in the final award group approved by the Department. Project developers in the final award group approved by the Department shall have the option of signing the long-run standard contract A or negotiating an alternative contract with the host electric company.

Long-Run Standard Contract B shall mean a standard contract that the host company shall make available to providers of supply-side resources with projects whose design capacity is not greater than five megawatts, or one percent of the host company's annual peak demand, whichever is lower. Project developers eligible for this contract are not required to participate in the all-resource solicitation in order to sell electricity to the electric company under the terms of long-run standard contract B, pursuant to 220 CMR 10.07(1).

Lost C&LM Opportunity shall mean the failure to take steps necessary to capture cost-effective C&LM savings at the time when it is most practical and inexpensive to do so, such as the point when a building is first constructed or when a customer's energy consuming equipment is replaced.

Natural C&LM shall mean C&LM that will occur without the intervention of the electric company either as a direct supplier or as a purchaser of third party C&LM services.

Peak Demand or Peak Load shall mean the maximum level of consumption of electrical energy in a system, or part thereof, expressed as the maximum megawatt load during a specified time period (e.g., day, week, month, year).

Performance-Based C&LM shall mean C&LM programs for which payment or cost recovery is based on the determination of capacity and energy savings measured by monitoring and evaluating customer consumption patterns.

Phase I shall mean the portion of the regulatory process, as set forth in 220 CMR 10.03.

Phase II shall mean the portion of the regulatory process, as set forth in 220 CMR 10.04.

Phase III shall mean the portion of the regulatory process, as set forth in 220 CMR 10.05.

Phase IV shall mean the portion of the regulatory process, as set forth in 220 CMR 10.06.

Planned Resource shall mean a resource that is contracted for or has received pre-approval but has not begun to provide kilowatts or kilowatt-hours to the electric company or decrease the kilowatt or kilowatt-hour requirements of the electric company or modify the time pattern of customer capacity or energy requirements.

Pre-approval shall mean the Department procedures for pre-approval of resources pursuant to 220 CMR 9.00, D.P.U. 86-36-F, and D.P.U. 86-36-G.

10.02: continued

Project Proposal shall mean a proposal for providing a demand-side or supply-side resource to the host electric company through the all-resource solicitation. A host electric company's project proposals shall be set forth in the initial resource portfolio; other entities' project proposals shall be submitted in response to an RFP. A project proposal shall include all of the terms and conditions required by the host electric company's RFP. A project proposal may include a portion of a generating facility or C&LM program, as well as the entire facility or program.

Project Developer shall mean any entity, including the host electric company and other electric companies, that submits project proposals for the all-resource solicitation.

Proposed Resource Plan shall mean the award group proposed by the host electric company for Department review in Phase III, as well as all of the documentation required to describe the selection of the proposed award group, pursuant to 220 CMR 10.05(2).

Qualifying Facility (QF) shall mean any small power producer or cogenerator that meets the criteria specified in 18 C.F.R. 292.203 (a) and (b).

Repowering shall mean a specific program implemented with respect to an existing supply-side resource where such program changes the combustion or generation configuration of the existing supply-side resource.

Resource shall mean any facility, technology, measure, plan or action that either generates kilowatts or kilowatt-hours, decreases the kilowatt or kilowatt-hour requirements of an electric company, or modifies the time pattern of customer capacity or energy requirements for the purpose of improving the efficiency of the electric company's operating system.

Resource Inventory shall mean the combination of existing and planned resources of an electric company.

Revenue Erosion from C&LM shall mean a situation in which C&LM measures or programs result in lower energy use than occurred in the test year of an electric company's most recent rate case, causing the electric company to sell less electricity than was assumed in the most recent rate case in establishing rates to produce the company's allowed revenue requirement.

Supply-Side Resource shall mean a resource that provides kilowatts or kilowatt-hours to the host electric company. Generation, transmission, and distribution systems may be considered supply-side resources to the extent that they increase the total amount of kilowatts or kilowatt-hours that can be provided to the electric company to meet the needs of its retail customers.

Technical Potential of C&LM shall mean the sum of potential energy and capacity savings that may be achieved by installing all state-of-the-art, commercially-available, efficiency technologies that yield the most energy and capacity savings for each end-use in each customer subsector, regardless of the cost or delivery mechanism. Technical potential should be based on the assumption that full market participation can be achieved, and should not be limited by current or anticipated C&LM programs.

Technical Potential of Demand-Side Resources shall mean the sum of potential capacity and energy savings that may be achieved by installing all state-of-the-art, commercially-available, conservation, load management, or fuel switching technologies that yield the most energy and capacity savings for each end-use in each customer class subsector, regardless of the cost or delivery mechanism. Technical potential should be based on the assumption that full market participation can be achieved and should not be limited by current or anticipated DSM programs.

10.02: continued

Technical Potential of Life Extension shall mean the kilowatts and kilowatt-hours provided by the continuation of existing supply-side resources beyond the retirement date of such resources resulting from state-of-the-art, available technologies for life extension, regardless of the cost of such continuation.

Technical Potential of Repowering shall mean the kilowatts and kilowatt-hours provided by the change in the combustion or generation configuration of an existing supply-side resource resulting from state-of-the-art, available technologies for repowering, regardless of the cost of such repowering but recognizing the physical constraints of the plant site.

Total Cost to Society shall include: (a) all direct costs to the electric company; (b) direct out-of-pocket costs or benefits to the electric company's customers; (c) social costs not internalized in either (a) or (b) above (e.g., environmental externalities); and (d) other nonprice factors affecting the costs or benefits of the electrical service (e.g., reliability, fuel diversity).

Wheeling shall mean the transmission of electricity by an electric company to another electric company from sources other than its own generation or purchased power sources.

10.03: PHASE I: Draft Initial Filing and Initial Filing Requirements and Regulatory Review

(1) Frequency of Filing. Each electric company shall submit to the Department an initial filing as defined below, pursuant to a schedule established by the Department. The filing schedule for each cycle after the first cycle shall be determined in the final Order of the previous cycle. Initial filings shall not be more frequent than 18 months, nor less frequent than 30 months from the previous initial filing.

(2) Documents to be Filed. Each electric company shall file the following documents.

(a) Draft Initial Filing. Each electric company shall submit a draft initial filing to the Department eleven weeks before the initial filing date established by the Department. In addition, the draft initial filing shall be made available to any person who so requests for purpose of participation in discussions at the technical sessions or in settlement negotiations. The draft initial filing shall be sufficiently complete to support meaningful discussion of the issues. If agreement is reached on any of the components of the draft initial filing, those components can be submitted as part of the company's initial filing.

(b) Initial Filing. Each electric company's initial filing shall contain the following documents.

1. Executive summary. The Executive Summary shall be a nontechnical summary of the information presented in each Technical Volume.

2. Technical Volumes.

a. The Demand Forecast shall include all of the information required by 220 CMR 10.03(6), and any other documentation that the company deems useful for Department review.

b. The Resource Inventory shall contain all of the information required by 220 CMR 10.03(7), and any other documentation that the company deems useful for Department review.

c. The Resource Need Evaluation shall contain all of the information required by 220 CMR 10.03(8), and any other documentation that the company deems useful for Department review.

d. The Resource Potential Evaluation shall contain all of the information required by 220 CMR 10.03(9), and any other documentation that the company deems useful for Department review.

e. The Resource Solicitation Request for Proposals shall contain all of the information required by 220 CMR 10.03(10) and any other documentation that the company deems useful for Department review.

f. The company's Initial Resource Portfolio shall contain all of the information required by 220 CMR 10.03(5) and any other documentation that the company deems useful for Department review.

10.03: continued

g. The Prefiling Settlement Package shall contain the agreements achieved, if any, of the prefiling settlement process, pursuant to 220 CMR 10.03(4), and any other documentation the company deems useful for Department review of a proposed settlement.

(3) Notice and Participation.

(a) Notice.

1. At least 11 weeks before the initial filing date established by the Department, the company shall submit a draft initial filing to the Department, whereupon the Department shall issue an Order of Notice to inform the public about the company's draft initial filing, technical sessions and Phase I initial filing.

2. Within ten days of the issuance of the Order of Notice, the electric company shall publish the notice in at least one newspaper of general circulation in the service territory, as approved by the Department, and send actual notice to any person that has filed a request for notice with the company.

(b) Intervention and Participation. Any person who wishes to intervene as a party or participate in the proceeding shall file a written request to the Department to intervene as a party or participate in the proceeding pursuant to 220 CMR 1.03, except that such requests shall be filed within ten business days of the publication of the Order of Notice. The Department may, at its discretion, hold hearings to consider the requests for intervenor or participant status.

(4) Prefiling Settlement Procedures.

(a) Technical Sessions.

1. The electric company shall hold at least one technical session at least eight weeks before the initial filing date established by the Department.

2. The purpose of the technical session is to

a. provide a basis for exchange of information and clarification of the draft initial filing, and

b. establish procedures and rules for further discussions designed to limit or settle issues, pursuant to 220 CMR 10.03(4)(b).

(b) Settlement Negotiations.

1. The electric company shall enter into discussions with parties for the purpose of evaluating the electric company's draft initial filing and for the purpose of reaching agreement among the parties on all or some issues in the draft initial filing.

2. The purpose of the settlement negotiations is to facilitate the Department's review of the initial filing by:

a. improving all parties' understanding of the company's draft initial filing;

b. reaching agreement among the parties to the maximum extent possible on the company's draft initial filing;

c. making agreed-upon improvements to the filing; and

d. identifying specific areas for adjudication, if necessary, before the Department.

3. Any settlement, partial settlement, or contested settlement reached by parties to the proceeding shall be filed with the Department in the electric company's Phase I initial filing. Any settlement, partial settlement, or contested settlement pertaining to the demand forecast, the committed resources, the resource need, the estimates of resource potential, the RFP, or the electric company's initial resource portfolio, shall be subject to Department review and approval.

4. Discussions and positions taken by the parties during the course of settlement negotiations shall be neither admissible nor subject to discovery during any adjudicatory proceeding. Facts disclosed during such settlement negotiations may be subject to discovery during any adjudicatory proceeding.

5. Staff members from the Department may participate in the settlement negotiations, in the same role as the parties. Any Department staff member that actively participates in the settlement negotiations shall be prohibited from advising the Commissioners of the

10.03: continued

Department in its review of the initial filing, or subsequent proceedings involving the review of that filing. The Commissioners of the Department shall not be bound on any matter agreed to by Department staff members during the settlement negotiations.

(c) Facilitation. The parties are encouraged to use an impartial party to facilitate the settlement negotiations. The Department may make staff members available for facilitation. Department staff members who facilitate the negotiations shall be prohibited from advising the Commissioners of the Department in their review of the initial filing, or subsequent proceedings involving the review of that filing. Facilitation expenses (e.g., those expenses incurred for facilitators, meeting rooms, etc.) shall be borne by the electric company.

(5) Initial Resource Portfolio. The company shall develop a specific initial resource portfolio for the purpose of meeting the need for additional resources. After the filing of its initial resource portfolio, the company may not change the terms and conditions of any proposed resource unless otherwise ordered by the Department.

(a) Initial Resource Portfolio Filing Requirements.

1. The initial resource portfolio shall be designed to meet the entire resource need identified by the Company.

2. The initial resource portfolio shall be designed to provide reliable electrical service to the company's ratepayers at the lowest total cost to society.

3. For each resource in its initial resource portfolio, the company shall provide all the information required of the RFP respondents to the all-resource solicitation, pursuant to 220 CMR 10.03(10), and all the information required for Department review of pre-approval rate treatment, pursuant to 220 CMR 9.00, except for output price, method of cost recovery, and cost information. Exceptions to this requirement are noted in 220 CMR 10.03(5)(a)4..

4. For resources in the initial resource portfolio in which the company has no ownership or other financial interest, the company shall file a general description of such resources including the following: name and address of the owner and operator of the project; a brief description of the project including the nature of the technologies employed; nameplate capacity (if appropriate); anticipated capacity and energy purchase or capacity and energy savings; location; fuel type (if any); development or operational status; and the anticipated operational date.

5. The initial resource portfolio shall include all cost-effective C&LM programs for all customer sectors and subsectors. Such programs shall avoid lost C&LM opportunities and cream-skimming to the maximum extent possible. For the purpose of developing the initial resource portfolio, cost-effective C&LM programs shall be determined by comparing those programs to the company's supply-side resources proposed for the initial resource portfolio, using the ranking system developed pursuant to 220 CMR 10.03(10)(d). In addition, C&LM programs that displace the energy requirements from existing and planned resources, at a lower total cost than the variable operation and maintenance cost, including fuel cost of those resources, shall be considered cost-effective.

6. The electric company shall separately identify the following elements of its initial resource portfolio:

a. resources that are proposed to be purchased from other entities and that have not yet been approved by the Department;

b. resources that are proposed to be purchased from other entities and that are not subject to Department approval;

c. electric company modifications to generating units requiring pre-approval by the Department;

d. additional electric company generation facilities not yet pre-approved by the Department;

e. additional electric company C&LM resources not yet existing or planned;

f. any existing or planned electric company-owned resource that the electric company proposes for its initial resource portfolio, and

10.03: continued

g. any other resource that the company proposes for its initial resource portfolio.

(6) Demand Forecast.

(a) Purpose and Scope. 220 CMR 10.03(6) sets forth the requirements for forecasts of demand. Projections of the demand for electricity shall be based on substantially accurate historical information and reasonable statistical projection methods. The electric company shall demonstrate that the demand forecast is: reviewable, that is, it contains enough information and sufficient documentation to allow full understanding of the forecasting methodology; appropriate, that is, it uses a methodology that produces a forecast that is technically suitable to the size and nature of the electric company that produced it; and reliable, that is, it uses a methodology that provides a measure of confidence that its data, assumptions, and judgments produce a forecast of what is most likely to occur. The demand forecast shall be subject to Department review in Phase I, pursuant to 220 CMR 10.03. Consistent with the findings on the demand forecast, the Department, in its Order, may 1. adjust or modify an electric company's forecast of resource need for the all-resource solicitation, or 2. stay the IRM process.

(b) Contents of Forecast.

1. Demand Forecast Characteristics. The base case demand forecast shall include historical data for a minimum of five calendar years preceding the year in which the initial filing is submitted, and projections for 20 calendar years beginning with the year in which the initial filing is submitted. In the case of an electric company that receives electrical service or system-wide supply planning from affiliated companies that do business in other states as well as in Massachusetts, the electric company shall file two separate demand forecasts: one for its Massachusetts service territory, and a second for the entire electric operation of the affiliated company. The electric company shall provide the following information:

a. total annual electrical energy demand for the electric company's service territory, with breakdowns for each of the customer classes specified in 220 CMR 10.03(6)(d);

b. total seasonal peak demands for the electric company's service territory, with breakdowns for each of the customer classes specified in 220 CMR 10.03(6)(d), for both summer and winter seasons;

c. annual service territory load factor;

d. annual service territory load duration curves;

e. service territory load profiles for representative days in both summer and winter seasons;

f. estimated transmission and distribution losses; and

g. capability responsibility based on NEPOOL practices and the electric company's reserve requirement.

2. Natural Conservation and Load Management. An electric company's projections of its demand for electricity shall include natural C&LM. The electric company shall quantify the effects of natural C&LM on demand, and include natural C&LM as a major determinant of demand. The electric company shall identify the following which are included in the demand forecast:

a. C&LM programs sponsored or mandated by federal, state, and local governments (e.g., building codes, appliance efficiency standards);

b. market-induced C&LM; and

c. market-induced self-generation (excluding sales to the company).

3. Natural Fuel Switching. An electric company's projections of its demand for electricity shall include projections of the natural switching of alternative fuels for electricity.

(c) Demand Forecast Methodology. The Department does not prescribe a particular methodology that must be used by an electric company in forecasting demand. The methodology selected by an electric company must be reviewable, appropriate, and reliable. The electric company shall describe the following components of its forecast methodology for each year of the forecast period:

10.03: continued

1. The major determinants of total annual electric energy demand and seasonal peak demand. Such description shall identify the source of the determinants and document how these determinants were incorporated in the demand forecast. At a minimum, the following determinants shall be described:
   a. demographic data and economic activity pertaining to the electric company's service territory;
   b. the electric company's projections of its price of electricity and the price elasticity of demand for electricity;
   c. the electric company's estimate of the substitution of electricity for other fuels in competing end-uses;
   d. behavioral factors which are expected to have a significant effect on electricity demand;
   e. federal, state, or local policies that are expected to have a significant effect on electricity demand;
   f. natural C&LM;
   g. natural fuel switching; and
   h. other relevant factors.

2. The sources and vintages of the major data components used in the demand forecast.

3. The methodologies used to acquire, organize, modify, and test the validity of data used in the demand forecast, and the techniques used to project electricity consumption based on such data.

4. The major models used in compiling the forecast, including a description of the model logic and identification of the key variables affecting the model's outcome.

5. The level of confidence associated with key dependent and independent variables used in the electric company's models, with a detailed explanation of the reasons in support of such level of confidence.

6. The major assumptions regarding the forecast of electricity demand, with a detailed explanation of the reasons in support of these major assumptions.

(d) Customer Classes. Each demand forecast shall include separate forecasts of total annual electric energy demand and seasonal peak loads for each customer class. Commercial classes shall be identified by building type. Industrial classes shall be identified by two-digit SIC code or grouping of SIC codes. All customer classes shall be disaggregated by end-use as appropriate. Separate forecasts shall be provided for each of the following customer classes:

1. residential without electric heating;
2. residential with electric heating;
3. total residential;
4. commercial;
5. industrial;
6. street lighting;
7. railway;
8. sales for resale;
9. losses, internal use, and unaccounted for; and
10. any other customer class.

(e) Sensitivity Analyses.

1. The demand forecast shall include sensitivity analyses of major assumptions contained in an electric company's forecast methodology.

2. The demand forecast shall include, in addition to the base case growth forecast, high demand growth and low demand growth scenario forecasts. Additional forecast analyses shall be provided by the electric company as appropriate. The high demand growth and low demand growth scenario forecasts shall include estimated annual energy and peak load growth rates over the forecast period, and a brief discussion of the key changes in the variables and assumptions relied upon to produce the high, base case, and low demand growth forecasts.

10.03: continued

(7) Resource Inventory.

(a) Purpose and Scope. 220 CMR 10.03(7) sets forth the requirements for determining an electric company's resource inventory. The electric company shall identify separately: existing supply-side resources; existing DSM resources; planned (i.e., resources that have DPU or FERC approval) supply-side resources; and planned DSM resources. The electric company shall apply attrition factors to the planned resources to account for the contingency that planned resources may not meet the electric company's expected commercial operation dates for such resources. The electric company may exclude an electric company-owned resource from the resource inventory and include such resource in its initial resource portfolio. All planned and existing resources shall be included in the resource inventory except for 1. those units, which due to extraordinary circumstances, are excluded by the Department from an electric company's resource inventory, and 2. those electric company-owned units which the electric company demonstrates should be excluded from its resource inventory. In addition, the performance of existing resources shall be reviewed to determine whether each unit's performance has been evaluated appropriately in the filing. The resource inventory shall be compared to the demand forecast to determine the electric company's additional resource need, described in 220 CMR 10.03(8). To facilitate the Department review, the electric company shall provide the information set forth in 220 CMR 10.03(7)(b) for the five calendar years preceding the year in which the initial filing is submitted, and the 20 calendar years beginning with the year in which the initial filing is submitted. The resource inventory shall be subject to Department review in Phase I, pursuant to this subsection. Consistent with the findings on the resource inventory, the Department in its Order, may adjust or modify the electric company's evaluation of resource need.

(b) Identification of Resources.

1. The electric company shall summarize the diversity of the company's capacity and energy resources in its resource inventory in the following categories:

a. resources owned fully or partially by the electric company relative to resources owned by other entities;

b. supply-side resources relative to DSM resources;

c. for demand-side resources, conservation resources relative to load management resources and fuel switching resources;

d. for supply-side resources, fuel type;

e. for supply-side resources, plant type (base load, intermediate, or peaking); and

f. for supply-side resources, plant size and technology.

2. Inventory of Existing Supply-Side Resources. Each electric company shall identify its existing supply-side resources, and provide the following information for each identified existing supply-side resource:

a. facility name and unit number, location, and owner;

b. percentage and quantity of host electric company's ownership of output;

c. in-service date;

d. nameplate capability rating (summer and winter);

e. current NEPOOL capability rating (summer and winter);

f. type of service (base, intermediate, peaking);

g. total acreage of the facility site;

h. annual production in kilowatt-hours;

i. capacity factor;

j. equivalent availability factor;

k. forced outage rate;

l. heat rate curve;

m. technology and design, including major pollution control equipment;

n. fuel types;

o. capital costs;

p. variable operating costs (both fuel and variable operation and maintenance costs, disaggregated);

q. fixed operation and maintenance costs;

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r. other costs such as waste disposal, decommissioning, insurance, and property taxes;

s. permit restrictions which limit operation;

t. environmental impacts such as airborne emission rates, water emission rates, solid waste disposal, hazardous waste disposal, water use, etc., reported in the same format that is required in the RFP pursuant to 220 CMR 10.03(10); and

u. remaining life of resource (anticipated expiration of equipment or contract without investment requiring pre-approval pursuant to 220 CMR 9.00), with full justification.

3. Inventory of Existing DSM Resources. Each electric company shall identify its existing DSM resources, and provide the following information for each identified existing DSM resource. The end-use of electricity and customer class shall be the basis for this inventory (e.g., industrial motors, residential water heating). This information shall include the:

a. annual energy and capacity savings for the lifetime of the resource, and the basis for the calculation of savings;

b. impact on summer and winter peak demand, described in kilowatts, for the lifetime of the resource;

c. technologies installed to obtain the foregoing savings;

d. variable, operating, and maintenance costs;

e. total incremental costs per kilowatt and kilowatt-hour; and

f. measurement or monitoring procedures.

4. Inventory of Planned Supply-Side Resources. Each electric company shall identify its planned supply-side resources, and provide the following information for each identified planned supply-side resource:

a. facility name and unit number, location, and owner;

b. percentage and quantity of host electric company's ownership of output;

c. expected in-service date;

d. megawatt capability (summer and winter);

e. all fuel types (indicate proportions);

f. type of service (base, intermediate, peaking);

g. annual production in kilowatt-hours;

h. capacity factor;

i. equivalent availability factor;

j. forced outage rate;

k. heat rate curve;

l. annual contract costs for energy and capacity;

m. anticipated retirement date or purchase agreement termination date;

n. status of power sales agreement or other contract between the host electric company and the project developer, specifying whether the contract has been approved by the appropriate agency;

o. status of fuel supply contracts and transportation;

p. status of all environmental and regulatory permits needed for the operation of the resource;

q. status of DPU pre-approval, if required, in the case of electric company-provided generation; and

r. status of the financing and construction of all relevant structures needed for the operation of the resource.

5. Inventory of Planned DSM Resources. Each electric company shall identify its planned DSM resources, and provide the following information for each identified planned DSM resource. The electricity end-use and customer class shall be the basis for this inventory (e.g., industrial motors, residential water heating). This information shall include the:

a. annual energy and capacity savings for the lifetime of the resource, and the basis for the calculation of savings;

b. estimated impact on summer and winter peak demand, described in kilowatts for the lifetime of the resource;

c. technologies planned to be implemented to obtain savings;

d. targeted market segments and end-uses, and the saturation level of the technology in such segments and end-uses prior to implementation of the resource.

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e. project details, including origin of the resource (i.e., specify solicitation or negotiation), project proponent, and the expiration date of the contract or termination date of the program;
f. contracts the host electric company has with project developers, and the status of contract approval by the Department, or other appropriate regulatory authority having jurisdiction over the purchase;
g. electric company DSM programs which include identified planned DSM resources. For such programs, the program title, a description of the program, pre-approval status, financial incentives for the electric company, and participation levels anticipated; and
h. description of major cost components of the electric company DSM programs, or contract costs for capacity and energy.

6. Attrition for Planned Resources. The electric company shall apply attrition factors to its inventory of planned supply-side resources and planned demand-side resources to account for the contingency that planned resources may not meet the electric company's expected commercial operation dates for such resources. The electric company shall provide sufficient documentation explaining and justifying the use of these attrition factors. The Department shall review the attrition factors for planned resources.

(8) Evaluation of Resource Need.

(a) Purpose and Scope. 220 CMR 10.03(8) sets forth the requirements for identifying the electric company's need for additional resources to provide reliable electrical service to customers at the least-cost with the least-environmental-impact. The characteristics of the additional resource need shall be used in establishing the electric company's all-resource solicitation pursuant to 220 CMR 10.00. The Department shall allow for solicitations of economical energy as part of the all-resource solicitation. The evaluation of resource need shall be subject to Department review in Phase I, pursuant to 220 CMR 10.03(8). Consistent with the findings on the demand forecast and the resource inventory, the Department, in its Order, may adjust or modify the electric company's evaluation of resource need.

(b) Identification of Resource Need.

1. The electric company shall identify the general characteristics of the resource need described by the difference between the electric company's demand forecast and the electric company's resource inventory.

2. Resources shall be solicited to meet the additional resource need identified for each year of the ten calendar years following the company's initial filing date, in the following terms:
a. kilowatts of summer capacity;
b. kilowatts of winter capacity;
c. kilowatt-hours of total annual energy requirements; and
d. capability responsibility based on NEPOOL practices and the electric company's reserve requirement.

If no additional capacity need has been identified for those ten years, then the RFP shall be for energy or energy savings only.

3. The electric company shall describe the general characteristics of the additional resource need identified, for the ten years following the company's initial filing date. This description shall include the following characteristics:
a. equivalent availability needs;
b. in-service date;
c. on-peak, off-peak and seasonal production requirements;
d. diversity objectives, including but not limited to:
i. resources owned fully or partially by the electric company relative to resources owned by other entities;
ii. supply-side resources relative to DSM resources;
iii. for demand-side resources, conservation resources relative to load management resources and fuel switching resources;
iv. for supply-side resources, fuel type;

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v. for supply-side resources, plant type (base load, intermediate, or peaking); and
vi. for supply-side resources, plant size and technology.
e. voltage control needs; and
f. locational needs.
If no additional capacity need has been identified for those ten years, then the RFP shall be for energy or energy savings only.

(9) Evaluation of Resource Potential.
(a) Technical Potential of DSM.
1. Purpose and Scope. 220 CMR 10.03(9) sets forth requirements for identifying all DSM technical potential in the host electric company's service territory. The electric company's assessment of the technical potential of DSM shall identify DSM program opportunities. The identification of the technical potential of DSM shall be subject to Department review in Phase I, pursuant to 220 CMR 10.03(9). The Department review shall focus on the electric company's process for identifying the technical potential of DSM.
2. Identification of Technical Potential of DSM. For each end-use with conservation, load management or fuel switching potential, the electric company shall identify and quantify the estimated additional capacity and energy savings associated with each such measure. For each type of DSM potential, the electric company shall estimate the energy and capacity savings assuming full installation of all technologies that yield the most energy and capacity savings, regardless of cost or delivery mechanisms and assuming full participation.
a. The electric company shall identify and quantify the estimated capacity and energy savings for each customer class sector and subsector (e.g., rental housing, two-digit SIC codes).
b. The electric company shall identify the most efficient potential conservation option, the most efficient potential load management option, and the most efficient fuel switching option for each end-use. For each end-use, the electric company shall provide the following information:
i. estimated energy and capacity savings for each end-use based on the full implementation of all conservation, load management and fuel switching options identified;
ii. estimated value of end-user benefits in addition to the energy savings attributable to the installation of particular conservation, load management and fuel switching improvements; and
iii. total estimated savings for the electric company's service territory, described in terms of energy and peak capacity, with specifications of savings in transmission and distribution line losses, and reduced reserve requirements.
c. The electric company shall specify which of the above DSM technologies have been implemented in existing DSM resources.
(b) Technical Potential of Life Extension or Repowering.
1. Purpose and Scope. 220 CMR 10.03(9)(b) sets forth the basic requirements for identifying all plant life extension or repowering potential. The electric company's assessment of technical potential of life extension or repowering will identify large blocks of power potentially available at existing power plants. The Department review shall focus on the electric company's process for identifying the technical potential of life extension or repowering.
2. Identification of Technical Potential of Life Extension or Repowering. For each plant with life extension or repowering potential, the electric company shall identify a wide range of options to modify the life, output, and performance of the plant without regard to cost or time. For each option, the electric company shall describe the significant actions needed for life-extending or repowering a plant, based on known plant conditions and state-of-the-art, commercially-available technologies. For each plant that the electric company owns or has applicable rights to, the electric company shall provide:
a. plant name and owner;
b. output received by the electric company;

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c. existing fuel type and technology;
d. type of service (base, intermediate, peaking); and
e. each potential option for life extension or repowering with the following information:
i. technologies and fuel type;
ii. operating or environmental permits that are expected to be required;
iii. necessary modifications;
iv. types of service (base, intermediate, peaking);
v. length of extension of useful life;
vi. capacity after life extension or repowering; and
vii. improvements in performance factors.

(10) Resource Solicitation Request for Proposals ("RFP").

(a) Purpose. The purpose of the RFP is to solicit resource proposals from project developers. The RFP shall solicit from project developers all information necessary to compare proposals and determine the mix of resources that is most likely to result in a reliable supply of electrical service at the lowest total cost to society. The RFP shall contain all information necessary for project developers to understand and compete fairly in the all-resource solicitation process. The RFP shall be subject to Department approval in Phase I, pursuant to 220 CMR 10.03(11).

(b) Supply-Side Versus Demand-Side Solicitations.

1. The company shall have the option to issue one RFP for all resources, or to issue separate RFPs for supply-side and demand-side resources. In either case, the company shall be responsible for integrating all available resources into a proposed resource plan, pursuant to 220 CMR 10.04(3). The Company's methodology for integrating all types of resources shall be clearly articulated in the RFP and shall be subject to Department review in Phase I, pursuant to 220 CMR 10.03(11).

2. If the electric company issues separate RFPs for supply-side and demand-side resources, the solicitation processes shall be performed in a parallel manner, under the same time frames and procedures pursuant to 220 CMR 10.04. Both supply-side and demand-side resources shall be considered for the entire resource need, i.e., the company shall not identify separate resource blocks for different resource types. Both supply-side and demand-side resources shall be evaluated using the same categories of selection criteria with the same relative weights, pursuant to 220 CMR 10.03(10)(d). The ranking systems may use different subscoring systems within each category. Each separate RFP shall contain all of the contents specified in 220 CMR 10.03(10)(c), as appropriate for the resource type.

(c) Content of the RFP.

1. The RFP shall be consistent with the other elements of the company's initial filing, i.e., the company's demand forecast, resource forecast, resource potential and resource need, and initial resource portfolio.

2. The RFP shall specify the amount of additional resources being solicited by the company in both megawatt ("MW") and megawatt-hour ("MWH") (or MW and MWH saved) per year and season based on the size and timing of the resource need identified pursuant to 220 CMR 10.03. Resources shall be solicited to meet the additional resource need identified for the ten years following the company's initial filing date. If no additional capacity need has been identified for those ten years, then the RFP shall be for energy or energy savings only.

3. The RFP shall specify the period within which the project proposals shall be filed with the company.

4. The RFP shall explain the ranking system and any other component of the company's process for selecting project proposals for the award group.

5. The RFP shall specify any minimum or maximum threshold values that potential project developers shall satisfy to be eligible for consideration in the ranking procedure.

6. The RFP shall require solicitation respondents to file sufficient information and supporting documentation to enable the company to evaluate project proposals pursuant to 220 CMR 10.03(10) and 10.04.

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7. For the purpose of assisting RFP respondents in developing project proposals, the RFP shall provide the following data and assumptions used by the company to develop the evaluation criteria and the initial resource portfolio and to evaluate project proposals pursuant to 220 CMR 10.04(3):
a. fuel price projection(s), for each fuel type;
b. general inflation rates and other cost escalation indices;
c. the discount rate;
d. a formula to assist RFP respondents in estimating interconnection costs;
e. a formula to assist RFP respondents in estimating wheeling and other transmission-related costs, and where appropriate, explicitly accounting for the number of service territories to be crossed;
f. pricing rules or constraints that the company adopts to evaluate project proposals; and
g. best available control technology (BACT) emission standards as adopted by the Department in consultation with the Department of Environmental Protection (DEP), for the purpose of the RFP process.
8. The RFP shall explain the negotiation and contracting procedure.
9. The RFP shall include the company's long-run standard contracts. The company shall prepare separate long-run standard contracts for generation projects and C&LM projects.
10. The RFP shall include the company's initial resource portfolio, developed pursuant to 220 CMR 10.03(5).
11. The RFP shall describe the company's method for evaluating and comparing project proposals whose contract lives extend over different time periods.

(d) Project Selection Criteria and Ranking System.
1. Each company shall adopt a ranking system to evaluate project proposals on the basis of each proposal's ability to provide reliable electrical service at the lowest total cost to society. The ranking system shall be used to determine the relative value of project proposals, for the purpose of developing the award group. Because the ranking system is only the initial step in developing the award group, pursuant to 220 CMR 10.04(3), project developers that receive a high rank are not guaranteed to be selected for the award group. The ranking system is subject to Department review in Phase I.
2. The ranking system shall incorporate all of the selection criteria that will be used to determine the rank order of project proposals. The ranking system shall apply relative weights to the major categories of criteria (e.g., price, the quality of output or savings, project feasibility), in order to identify the relative importance of these categories in selecting resources. The ranking system shall specify, in qualitative terms, how the criteria shall be applied to specific project proposals. The ranking system may be, but need not be, self-scoring.
3. The ranking system shall include categories for at least the following criteria:
a. The proposed price.
i. To evaluate the proposed price, the company shall require the project developer to submit a price proposal for the energy and capacity the proposed project is expected to generate or save. The price proposals may be submitted on a total period basis or a time-of-supply basis.
ii. To evaluate the proposed price, the company shall require the project developer to submit a pricing formula defining the timing of the price payments. The project developer may request any reasonable pricing formula. The ranking system should be more favorable towards those price patterns that are less risky from the ratepayers' point of view.
iii. To evaluate the proposed price of demand-side project proposals, the company shall require demand-side project developers to submit price formulas that specify:
- the payments to be made by the electric company to the developer;
- contributions to the cost of C&LM measures to be made by the customer.

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b. The quality of output or savings.
i. To measure quality of output of supply-side resources, the company shall require the project developer to file the following information for generating facilities:
- capacity, by season;
- equivalent availability;
- dispatchability;
- interruptibility;
- voltage control;
- ability to coordinate maintenance with the company;
- location on the transmission and distribution system; and
- fuel and technology choice.

ii. To measure quality of savings of demand-side resources, the company shall require the project developer to file the following information for C&LM projects:
- capacity, by season;
- availability, by hours of the day, season, or time of year;
- dispatchability;
- interruptibility;
- proposed method by which savings shall be measured and monitored; and
- the degree to which the project addresses cream-skimming, lost opportunities, hard-to-reach sectors, and other equity concerns.

c. The timing of output or savings. Timing of output or savings for supply-side or demand-side resources shall be measured by the following criteria:
i. proposed contract period;
ii. in-service date;
iii. on-peak, off-peak, and seasonal production or savings; and
iv. flexibility to alter scheduled delivery date.

d. Project feasibility. A project's likelihood of success shall be evaluated by the following factors:
i. degree of control of the site for the proposed facility (including ownership, lease, option to buy or lease, or other indications of degree of control);
ii. siting and environmental permits needed and obtained;
iii. equipment contracts needed and obtained;
iv. fuel contracts needed and obtained;
v. project design and engineering needed and completed;
vi. financial arrangements completed;
vii. degree of financial resources of the developer;
viii. degree of security provided for front-loaded payment contracts (see 220 CMR 10.06(2)(h));
ix. willingness to provide in-service security deposits above minimum required levels (see 220 CMR 10.06(2)(i));
x. experience of the project developer;
xi. degree of project construction or implementation completion; and
xii. other criteria that the company considers applicable.

e. Fuel diversity.

f. Externalities. Environmental externalities shall be monetized to the greatest extent possible and added to direct resource costs for the purposes of evaluating and comparing project proposals. The Department may periodically modify the environmental externality values used to evaluate and compare project proposals pursuant to 220 CMR 10.00.

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g. BACT emission standards. Project proposals shall be evaluated on whether they meet projected BACT emission standards as adopted by the Department in consultation with the DEP, for the purposes of the RFP process.
h. Other factors. The ranking system may include other factors. Utilities may ask project developers to file other information relevant to a project's effect on total cost to society.

4. The goal of the company's ranking system shall be to determine the mix of resources that is most likely to result in a reliable supply of electrical service at the lowest total cost to society.
5. The ranking system shall incorporate and clearly articulate a method for comparing generating projects and C&LM projects.
6. The company shall develop and clearly articulate minimum and/or maximum threshold values on any of the above ranking criteria. Project proposals that do not meet these standards shall be denied further consideration in the ranking procedure.
7. The electric company shall base the selection criteria on the anticipated resource need and resource potential evaluation proposed in the initial filing. The basis for the proposed initial resource portfolio shall be consistent with the basis for the company's selection criteria.
8. The electric company shall submit sufficient documentation of the assumptions, models, and any other relevant information to justify its project selection criteria and its application of them pursuant to 220 CMR 10.05.
9. The electric company shall identify any reasons that may cause it to deviate from the project ranking system in determining the proposed award group, pursuant to 220 CMR 10.04(3).

(11) Department Review of the Initial Filing.
(a) The Department shall open an investigation on the electric company's initial filing and proposed RFP. The Department shall hold a public hearing, and may hold adjudicatory hearings and technical sessions as the public interest requires. The electric company's initial filing and proposed RFP shall be approved if found to comply with 220 CMR 10.00.
(b) The Department shall review each electric company's initial filing with respect to the demand forecast, the resource inventory, the evaluation of resource need, the evaluation of resource potential, and the RFP. The Department shall issue an Order on the company's initial filing within five months of the initial filing date. If the Department does not issue an Order within five months, the electric company's initial filing and proposed RFP shall be deemed approved by the Department.
(c) The electric company shall revise its initial resource portfolio if the Department orders a material and substantial change to the initial resource portfolio resulting from the findings on the demand forecast, resource inventory, or evaluation of resource need. The electric company shall submit its revised initial resource portfolio within the time frame specified in the Department's Order on the initial filing, but no later than 60 days from the issuance of the Department's Order. The Department, on its own motion, may investigate the revised initial resource portfolio to determine whether the company has complied with the Department's Order.
(d) If the Department finds that issuance of the company's RFP as proposed is not in the public interest, the company shall revise the RFP as required by Department Order. The electric company shall submit its revised RFP within the time frame specified in the Department's Order, but no later than 60 days from the issuance of such Order. The Department, on its own motion, may investigate the revised RFP to determine whether the company has complied with the Department's Order.
(e) The Department shall review the adequacy of the electric company's supply plan in the short run as part of its review of the initial filing. In the initial filing, the electric company shall demonstrate the adequacy of its supply plan to meet demand in the short-run. An electric company must demonstrate that it owns or has under contract sufficient resources to meet its capability responsibility under a reasonable range of contingencies in the

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short run. If an electric company cannot establish that it has adequate resources in the short run, the electric company shall demonstrate that it operates pursuant to a specific action plan guiding it in being able to rely upon alternative resources in the event of certain contingencies. The electric company shall compare its resource inventory, as identified pursuant to 220 CMR 10.03(7), with forecasted demand, as identified pursuant to 220 CMR 10.03(6), for the short run. For the purposes of the initial filing, the short run shall be defined as the time period extending four calendar years beginning with the year in which the initial filing is submitted.

10.04: PHASE II: Solicitation Process and Project Evaluation

(1) Purpose. After the Department has approved the company's initial filing and RFP in Phase I, pursuant to 220 CMR 10.03, the company shall solicit resource proposals from project developers by issuing the RFP. The company shall apply the RFP ranking system and selection criteria to compare project proposals from all project developers, in order to determine the mix of resources that is most likely to result in a reliable supply of electrical service at the lowest total cost to society. That mix of resources constituting the electric company's proposed award group shall be subject to Department review in Phase III, pursuant to 220 CMR 10.05.

(2) Solicitation Process.
(a) The RFP shall be approved by the Department in Phase I, pursuant to 220 CMR 10.03(11), before it is issued by the company.
(b) Notice.
1. For the purpose of notifying potential project developers, the company shall publish a notice of the approved RFP in at least one newspaper of general circulation in the service territory as approved by the Department. The company shall likewise notify in writing any person or group that has filed a request for notice with the company. All notices shall be published and sent within five business days after the Department has approved a company's RFP.
2. The notice shall, at a minimum, contain the following:
a. a description of the resource need, as determined by the Department's Phase I Order;
b. the procedure for filing a project proposal with the company;
c. a definition of the solicitation period; and
d. the name of a contact person at the company who shall assist potential developers and answer questions.
(c) Solicitation Period. The electric company shall receive project proposals in response to the RFP during the solicitation period specified in the RFP. The solicitation period shall extend for no less than 90 days and no more than 120 days from the day that the RFP is approved by the Department.
(d) A project developer may submit only one proposal per facility in response to any particular solicitation. However, project developers may submit different size increments for each project proposal, for the purpose of best fitting the electric company's resource need. Project developers may submit project proposals representing the same facility to different utilities holding concurrent solicitations.
(e) Project proposals shall remain sealed until the solicitation period has expired.
(f) The Host Electric Company's Price Proposal. By 5:00 p.m. on the business day before the last day of the solicitation period, the company shall submit to the Department the company's proposed output price, cost recovery proposal, and relevant cost information for each of the resources proposed by the electric company in its initial resource portfolio. The electric company's price proposals shall remain sealed, and shall not be opened by the Department or be subject to public inspection until the solicitation period has expired.
(g) Proposed Resource Plan. The company shall file a proposed resource plan with the Department within 90 days of the end of the solicitation period. The proposed resource plan shall describe the proposed award group developed pursuant to 220 CMR 10.04(3), and shall include all documentation of the proposed award group as required in 220 CMR 10.05(2).

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(3) Development of the Award Group.

(a) Screening. The company shall screen all project proposals to eliminate those that do not meet the threshold requirements identified in the RFP, pursuant to 220 CMR 10.03(10)(d)6.

(b) Verification. The company shall verify all projects that are considered for the proposed award group. Verification shall include determining whether all of the representations made by the project developer regarding the initial project proposal are accurate, achievable, and reasonable. The company may request additional information to verify the terms and conditions of the initial project proposal.

(c) Initial Ranking. The company shall apply the ranking system, as described in the approved RFP, to each project proposal that meets the threshold requirements identified in the RFP. Project proposals shall be ranked according to how well they fulfill the RFP criteria on an individual project basis. The resulting ranking of all projects that meet the threshold requirements shall be called the initial ranking.

(d) Improving the Initial Ranking. The company shall evaluate whether the best project proposals from the initial ranking that fill the entire resource need, in combination with existing and planned resources, is the mix of resources that is most likely to result in a reliable supply of electrical service at the lowest total cost to society. The company shall propose an alternate mix of resources, called the improved ranking, if it can demonstrate that such a mix of resources is more likely than the initial ranking to result in a reliable supply of electrical service at the lowest total cost to society. The improved ranking shall include all project proposals that meet the threshold requirements identified in the RFP, pursuant to 220 CMR 10.03(10)(d)6. The justification for selecting a mix of resources that deviates from that of the initial ranking shall be based on the reasons identified in the RFP pursuant to 220 CMR 10.03(10)(d)9, and shall be subject to Department review in Phase III.

(e) Negotiation.

1. For the purposes of negotiation, the company shall determine a negotiating group that shall include, at a minimum, the best projects from the improved ranking that fill 130% of the size, in megawatts, of the largest resource need projected in any one of first ten years of the demand and supply forecasts approved by the Department pursuant to 220 CMR 10.00. For the purpose of calculating the size of the negotiating group, the size of the largest resource need shall also include the size of the resources identified by the Department as candidates for replacement by new resources. The company shall include in the negotiating group the marginal project that has any portion of its capacity falling within the 130% limit.

2. The company may, at its discretion, negotiate with more project developers than required by 220 CMR 10.04(3)(e)1. If the company chooses to negotiate changes to a project proposal whose rank from the improved ranking does not fall within the 130% requirement as specified in 220 CMR 10.04(3)(e)1, the company must include in the negotiating group all of the best projects from the improved ranking up to the rank of the project proposal with whom the company chooses to negotiate. After the company determines the improved ranking group, and before the company submits its proposed award group for Department review, the electric company shall give each developer within the negotiating group the opportunity to revise its project proposal. Proposed price and nonprice factors shall be revised only in such a way that the final resource plan would be improved. Before the company submits its proposed award group for Department review, the company shall not revise its own resource proposals filed in its initial resource portfolio.

(f) The Award Group. The electric company shall determine a proposed award group to fill, at a minimum, 100% of the resource need as identified by the Department. In its award group proposal, the company must replace resources designated by the Department as not committed, if such replacement results in lower total costs to society. The proposed award group shall include those projects that result in the optimal resource plan after the company has completed the negotiation pursuant to 220 CMR 10.04(3)(e). The proposed award group shall be subject to Department review in Phase III, pursuant to 220 CMR 10.05.

10.05: PHASE III: Resource Plan Filing Requirements and Regulatory Review

(1) Purpose. The Department shall review the company's proposed resource plan to ensure that the plan contains the mix of resources that is most likely to result in a reliable supply of electrical service at the lowest total cost to society. Project proposals in the proposed award group shall be approved by the Department before the company can begin the contracting procedures pursuant to 220 CMR 10.06.

(2) Filing Requirements.

(a) Within 90 days of the end of the solicitation period, the company shall file its proposed resource plan summary and proposed resource plan with the Department. The proposed resource plan summary shall describe the proposed award group developed pursuant to 220 CMR 10.04(3) and shall include at least the following information about the projects: name and address of the owner and operator of the project; a brief description of the project including the nature of the technologies employed; nameplate capacity (if appropriate); anticipated capacity and energy purchase or capacity and energy savings; location; fuel type (if any); development or operational status; the anticipated operational date; and ranking. The company shall distribute copies of the resource plan summaries to all entities submitting a project proposal, and shall make the resource plan summaries available at the company's primary place of business for public inspection.

(b) The electric company shall separately identify existing and planned resources, resources selected from the host company's initial resource portfolio, and projects selected from developers other than the host electric company. The electric company shall explain how these resources will meet the company's resource need and selection criteria identified in the RFP.

(c) Proprietary Treatment. For each project proposal selected for the proposed award group, the electric company shall include all of the information required in the RFP. The electric company shall indicate to the Department the portions of project proposals for which the project developer requests proprietary treatment. The Department shall exercise its express authority to protect confidentiality to the extent possible consistent with the provisions of M.G.L. c. 25, s. 5D. Project developers who request proprietary treatment for portions of project proposals shall submit two proposals in response to the RFP -- one for distribution to the general public, and one containing the entire proposal --which shall be reviewed by the Department and treated as proprietary information.

(d) For each electric company resource selected for the proposed award group, the electric company shall provide all the information required of the RFP respondents to the all-resource solicitation, pursuant to 220 CMR 10.03(10), including output price, method of cost recovery, and other relevant cost information consistent with any information filed confidentially at the end of the solicitation period.

(e) Results of the Initial Ranking System. The electric company shall include the results of applying the ranking system to all project proposals, including those that were not selected for the proposed award group, and including the host electric company's proposals.

(f) Documentation of the Initial Ranking System. The electric company shall include complete documentation of how the initial RFP ranking system was applied to all project proposals, including the company's own proposals in its initial resource portfolio. Documentation shall include all assumptions, methodologies, and computer model simulations used to rank alternatives.

(g) Justification for Improving the Initial Ranking. If the selection of projects for the improved ranking deviates from the results of the initial RFP ranking system, the electric company shall demonstrate the reasonableness of its decision(s) in reordering projects for the improved ranking. The electric company plan shall include complete documentation and justification for all resource selection decisions that were made on any basis other than the approved ranking system. Documentation shall include all assumptions, methodologies, and computer model simulations used to select alternatives. Justification shall include a description and explanation of any subjective factors that were applied in the decision.

10.05: continued

(h) Justification of Negotiation Results. The Company shall report the results of negotiations with project developers and explain how these negotiations affected the composition of the proposed award group. If the selection of projects for the proposed award group deviates from the results of the RFP ranking system or the improved ranking, the electric company shall demonstrate the reasonableness of its decision(s) to reorder projects for the proposed award group. Justification shall include a description and explanation of all factors that were a matter of negotiation.

(i) Preapproval Information. For each resource, demand-side or supply-side, that was in the host electric company's initial resource portfolio and is in the company's proposed award group, the electric company shall provide all the information required for Department review for pre-approval ratemaking treatment, pursuant to 220 CMR 9.00, including detailed cost information, output price, and proposed method of cost recovery.

(j) Revenue Erosion Information. For each C&LM resource for which the company requests ratemaking treatment to compensate for revenue erosion, the electric company shall provide sufficient documentation to demonstrate that the performance of the C&LM resource will result in revenue erosion that adversely affects the company's revenues in a significant, quantifiable way.

(k) For each resource purchased from project developers other than the host electric company, the company shall specify the ratemaking treatment for the proposed resource and shall include sufficient explanation, documentation, and justification for the specific ratemaking treatment proposal.

(3) Department Review.

(a) The Department shall review the electric company's proposed resource plan. The Department shall hold adjudicatory hearings, and may hold technical sessions at its discretion.

(b) The electric company's proposed resource plan shall be approved if found to comply with 220 CMR 10.00. The electric company's proposed award group shall be approved if found to include the mix of resources that has the highest likelihood of resulting in a reliable supply of electrical service at the lowest total cost to society.

(c) The Department shall issue an Order on the electric company's proposed resource plan within 90 days of the plan's filing date. If the Department does not issue such Order within 90 days, the Company's proposed resource plan shall be deemed approved by the Department.

(d) If the Department finds in the Order that the proposed resource plan does not comply with 220 CMR 10.00, the electric company shall submit a compliance filing in response to the Department's Order. The compliance filing shall be filed within the time period specified in the Order.

(e) The Department may approve any portion of the projects in the electric company's proposed award group before approving all projects in the award group. The Department may, at its discretion, issue interim Orders identifying the projects that have been approved. The electric company may proceed to negotiate contract terms for those approved projects, pursuant to 220 CMR 10.06(2), upon the issuance of the interim Order.

(4) Replacing Award Group Projects That Are Canceled.

(a) If any project selected for the final award group is subsequently canceled, abandoned, or rejected for any reason by any party within six months after the Department approves the final award group, the company shall attempt to replace the project with another project, or projects, from the most recently completed solicitation. If the company is unable to replace the lost project from the most recently completed solicitation, then the company shall describe to the Department in writing the reasons for the company's inability to do so.

10.05: continued

(b) The replacement project should be chosen so that the final mix of resources is most likely to result in a reliable supply of electrical service at the lowest total cost to society. The company shall justify to the Department in writing the basis for selecting the replacement project.
(c) The other resources selected for the final award group shall not be affected by the cancellation, abandonment, or rejection of specific projects.
(d) If any project selected for the final award group is subsequently canceled, abandoned, or rejected for any reason by any party more than six months after the Department approves the final award group, the company shall use its discretion, depending on its resource needs, whether or not to replace the project from the most recent solicitation.

10.06: PHASE IV: Resource Contracting Procedure

(1) Preapproval Contracting for Electric Company Resources. After Department approval of the resource plan, all electric company resources that are subject to pre-approval shall be reviewed by the Department, pursuant to 220 CMR 9.00.

(2) Contract Negotiations with Project Developers.
(a) Purpose. The electric company shall negotiate contracts with project developers, after Department approval of projects for the final award group in Phase III. Final contracts shall be filed with the Department for approval during Phase IV. For the purposes of 220 CMR 10.00, the company may sign long-run power purchase contracts only with projects approved by the Department for the final award group. Exceptions are described in 220 CMR 10.07.
(b) Once the project developer receives notice from the company that the developer's proposal has been approved by the Department in Phase III for inclusion in the company's final award group, the developer shall notify the company that it intends to go forward with the proposal in full. The developer shall also withdraw project proposals representing the same capacity and energy from the facility from the solicitations of other companies within five business days in order to retain its place in the final award group.
(c) The electric company shall begin finalizing power purchase contracts for projects immediately after they have been approved by the Department for the final award group.
(d) The electric company and the project developer shall agree to a pricing formula and other terms and conditions that are consistent with the price and terms and conditions of the project proposal approved by the Department in Phase III.
(e) If payments to project developers are based on cents per delivered kilowatt-hour and are time-differentiated to reflect changes in electric company cost patterns over time, then other operating performance criteria are required. If the project developer agrees to be operated under economic dispatch, then the purchase price should be adjusted by operating performance adjustments such as, but not limited to, the proposed project's equivalent availability factor; such performance adjustments are subject to the Department's approval.
(f) For demand-side and supply-side projects, savings measurement and contractual agreements shall be performance-based to the greatest extent possible.
(g) Reasonable project development milestone schedules must be included in resource contracts and must be mutually agreed upon by the company and the project developer.

10.06: continued

(h) Front-Loading Security. Front-loading security is required on all contracts whose expected payment to the project developer at any point in time will exceed the real levelized total cost of the project to the electric company's ratepayers. In calculating this real levelized total cost, the host electric company's marginal cost of capital shall be used for the discount rate, and the long-run consumer price index shall be used to calculate the rate of inflation. If front-loading security is required, supply-side project developers shall, at a minimum, make the purchasing company a lien holder on its total power production facility. The company's ranking formula may recognize tradeoffs in net ratepayer benefits between risk and front-loading security and allow project developers to provide additional security in order to receive a higher ranking. The amount to be secured and the security instrument shall be determined and fixed before the contract is signed. Front-loading security shall not be required for those contracts whose expected payment to the project developer at any point in time does not exceed the real levelized total cost of the project.

(i) In-Service Security.

1. Once a contract has been signed by both parties, the project developer is required, at a minimum, to put a deposit of $15 per kilowatt in an in-service security account controlled by the company. The amount may be adjusted periodically by the Department. The deposit shall either be cash (to be held in a mutually acceptable, interest-bearing escrow account), an irrevocable letter of credit (to be held by the company), or some other mutually agreeable security. The company's ranking formula may allow project proposals to receive a higher ranking if the project developer proposes to pay a contract deposit in excess of the $15 per kilowatt minimum or proposes a more secure instrument of security. The deposit shall be received by the company within 30 days after the contract is signed.

2. If the project is canceled by the project developer before the proposed in-service date, the security shall be returned to the project developer after payment to the company of the accumulated interest and a percentage of the principal equal to the following:

$$\text{Percentage of Principle} = \frac{\text{Elapsed time between contract signing and cancellation date}}{\text{Total time between contract signing and proposed in-service date.}}$$

3. If the project is canceled or abandoned after the proposed in-service date, the entire security plus any accumulated interest shall be paid to the company and the contract shall be canceled.

4. If the project reaches commercial operation on or before the in-service date, the entire deposit and accumulated interest are to be returned to the project developer.

5. If the project developer reaches commercial operation after its proposed in-service date, the principal and interest through the proposed in-service date are to be returned to the project developer and additional interest shall be paid to the company.

6. If the project has not reached commercial operation within 24 months after the proposed in-service date, it shall be deemed canceled and the entire security plus any accumulated interest shall be paid to the company, and the contract shall be canceled.

7. If approved by the Department, the parties may agree to alternative in-service security provisions keyed to more specific project development milestones or performance criteria. The company's ranking system may allow project proposals to receive a higher ranking if the project developer proposes alternative in-service security provisions keyed to more specific project development milestones or performance criteria.

10.06: continued

(j) If a final award group project developer agrees to the terms and conditions of the long-run standard contract at the time of contract finalization, the company is required to sign the long-run standard contract without further negotiation. If the project developer's project proposal had requested significant material changes in the long-run standard contract, the project developer and company may negotiate these items consistent with the provisions of 220 CMR 10.00. If after 30 days the parties cannot reach a settlement, the parties may petition the Department for a review. As long as these negotiations were conducted in good faith and the representations made in the project proposal are still true, the project developer cannot lose its place in the ranking until otherwise determined by the Department.

(k) The company is required to sign long-run standard contract A for any appropriate time period specified in a final award group project proposal.

(l) During contract finalization the electric company may initiate, at the electric company's option, negotiations with the project developer on price and nonprice factors. Price and nonprice factors shall be altered only in such a way that the project's score would be improved relative to other projects in the final award group.

(m) If a company's process is not complete within four months after the Department approves the resource plan, the Department, on its own motion, may investigate the company's contracting process to determine whether the process was conducted fairly and in the public interest.

(3) Department Review.

(a) During Phase IV, the Department shall review final contracts reached between the electric company and project developers to determine whether they comply with 220 CMR 10.00 and are in the public interest. The Department shall approve or disapprove any such contracts within 30 days of their filing with the Department. If the Department does not issue an Order on such a contract within 30 days of its filing, then the contract shall be deemed approved by the Department.

(b) When filing final contracts, the electric company shall indicate how the filed contract varies from the approved long-run standard contract A, and how the terms of the contract vary from the terms of the project proposal approved by the Department pursuant to 220 CMR 10.05(3).

(4) Utility Cost Recovery.

(a) Costs incurred by an electric company for the acquisition of electricity or electricity savings pursuant to 220 CMR 10.00 are recoverable through the rates charged to the company's customers for the term of the resource acquisition agreement where the rates, terms and conditions for the resource acquisition have been approved by the Department.

(b) Where the Department approves the replacement of an existing or planned resource (irrespective of ownership), whose cost recovery terms and conditions have been approved previously by the Department, with a new resource pursuant to 220 CMR 10.04(3) and 10.03, the sunk investment or unavoidable costs associated with the replaced resource (including the portion of sunk investment incorporated within the price formula of purchase power contracts) are recoverable through the rates charged to the electric company's customers.

10.07: Other Rules

(1) Optional contracting procedure for small generators.

(a) For supply-side projects whose design capacity is not greater than five megawatts, or one percent of the host company's annual peak demand, whichever is lower, the project developer may enter into long-run standard contract B. The company shall offer a purchase price, through long-run standard contract B, equivalent in value, on a present-worth basis, to the weighted average stream of contractually-set prices paid to all of the project developers from the most recent final award group. The company shall offer a variety of appropriate pricing formulas (e.g., floor price with escalating pricing provisions, levelized, fixed escalation, composite, derived heat rate, etc.) through long-run standard contract B. A project developer

10.07: continued

selecting this option does not have to participate in the solicitation process. The host company may not use long-run standard contract B for its own projects, which shall participate in the solicitation process.
(b) Project developers selecting this option shall be paid on a time-of-supply basis pursuant to 220 CMR 10.06(2)(e), shall comply with the front-loading security requirements pursuant to 220 CMR 10.06(2)(h), and shall provide a $10 per kilowatt in-service security deposit pursuant to the requirements in 220 CMR 10.06(2)(i). If the project developer agrees to a pricing formula that does not exceed the projected real levelized total price of the project at any time during the term of the contract, the company shall offer long-run standard contract B to this project developer without any additional performance or security provisions. Maximum contract length is 20 years.

(2) Effective rates, prices, and charges established pursuant to 220 CMR 10.00 shall be maintained at the company's place of business.

(3) If, at any time, a project developer is aggrieved by an action of a company pursuant to 220 CMR 10.00, the project developer may petition the Department to investigate such action. The Department may, at its discretion, open an investigation and, if it deems necessary, hold public hearings regarding any such petition.

(4) Intercycle Forecasts.
(a) Purpose and Scope. 220 CMR 10.07(4) sets forth the requirements for intercycle forecasts and supply plans which electric companies must file in each calendar year when the electric company is not required to submit an initial filing. The intercycle forecasts and supply plans shall be submitted in order that the Department may review (1) any significant changes or proposed changes in the demand forecast, resource inventory, evaluation of resource need, evaluation of the technical potential of DSM, and evaluation of the technical potential of life extension or repowering, and (2) the adequacy of the electric company's supply plan in the short run. The Department, in its discretion, may conduct an adjudicatory proceeding with respect to intercycle forecasts and supply plans pursuant to 220 CMR 1.00.
(b) Content of Forecasts. The electric company shall provide a narrative explanation of significant changes or proposed changes in the electric company's demand forecast, resource inventory, evaluation of resource need, and evaluation of resource potential. The Department may require the electric company to include additional information in the intercycle forecast and supply plan if the demand forecast or any separate forecast contained therein was rejected by the Department in the review of the previous initial filing. The electric company shall respond to any Orders set forth by the Department in the previous Phase I IRM final decision. Any planned supply-side resource or demand-side resource that has become operational since the previous review of the initial filing shall be identified in the intercycle forecast and supply plan. The electric company shall provide a comparison of the resource inventory and the demand forecast for the ten calendar years beginning with the year in which the intercycle forecast and supply plan is submitted. The electric company shall demonstrate that it owns or has under contract sufficient resources to meet its capability responsibility under a reasonable range of contingencies in the short run. If an electric company cannot establish that it has adequate supplies in the short run, the electric company shall demonstrate that it operates pursuant to a specific action plan guiding it in being able to rely upon alternative supplies in the event of certain contingencies. The electric company shall compare the resource inventory with demand forecast for the short run. For the purposes of the intercycle forecast and supply plan, the short run shall be defined as the time period extending four calendar years beginning with the year in which the intercycle forecast and supply plan is submitted.

10.07: continued

(5) The Department may, where appropriate, grant an exception to any provision of 220 CMR 10.00.

REGULATORY AUTHORITY

220 CMR 10.00: M.G.L. c. 164, ss. 76,94,94B and 96G

The Commonwealth of Massachusetts

DEPARTMENT OF PUBLIC UTILITIES

August 31, 1990

D.P.U. 89-239

Investigation by the Department of Public Utilities on its own motion into proposed rules to implement integrated resource management practices for electric companies in the Commonwealth.

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I. INTRODUCTION

On December 6, 1989, the Department of Public Utilities ("Department") issued an Order and proposed regulations regarding the procedures by which resources are planned, solicited, and procured by electric companies, and the appropriate ratemaking treatment to be afforded the implementation of such integrated resource management ("IRM") practices. D.P.U. 86-36-G (1989).[1] This comprehensive process requires regulatory review of electric companies' IRM practices by both the Department and the Energy Facilities Siting Council ("EFSC") in the exercise of each agency's statutory authority. On July 5, 1990, the EFSC issued an Order and proposed regulations (980 C.M.R. 12.00) for its portion of the IRM regulatory framework. See EFSC 90-RM-100 (1990).[2]

The procedural background of this rulemaking is as follows: On February 3, 1986, the Department opened an investigation into the pricing and ratemaking treatment to be afforded new electric generating facilities that are not qualifying facilities ("QFs")

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1 The Department established docket D.P.U. 89-239 as the formal rulemaking docket in this continuing IRM investigation. D.P.U. 86-36-G, p. 125 (1989).

2 The EFSC is scheduled to conduct a public hearing on its proposed regulations on September 5, 1990. The Department will participate in this public hearing.

as defined in our regulation overning the sale of electricity by small power producers and cogenerators. 220 C.M.R. 8.00; D.P.U. 86-36-A (1986). The Department structured D.P.U. 86-36 as a rulemaking proceeding to allow a comprehensive investigation of the broad range of issues pertaining to the impact of various alternatives for new utility investment in electric generating facilities. D.P.U. 86-36-C, p. 5 (1988). The proceeding's purpose has been to establish a regulatory framework that will result in each electric company's meeting its obligation to serve reliably and at the lowest possible cost. The Department has been investigating, through various phases of this proceeding, options for cost recovery of new generation investment by electric companies and methods of ensuring the inclusion of all appropriate resources including QFs, independent power producers ("IPPs") and conservation and load management ("C&LM") measures and other demand-side management ("DSM") options, as part of a utility's least-cost integrated (supply and demand) planning process. D.P.U. 86-36-G, p. 1 (1989).[3]

In D.P.U. 86-36-G, the Department proposed a regulatory structure in which the Department and the EFSC would systematically review the electric companies' procurement of

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3 For the complete history and scope of this investigation, see D.P.U. 86-36-C and D.P.U. 86-36-G and the Orders cited therein.

resources. The Order issuing the proposed regulations considered the need for an appropriate balance between such attributes as the flexibility in resource acquisition and the reviewability of the choice of resource alternatives; utility participation in its own solicitation and safeguards against self-dealing; the disclosure of pricing and other information for public review requirements and the competitive interests of utilities; and the need for flexibility to improve elements of resource acquisition through negotiation and precautions necessary to ensure the integrity of the competitive resource solicitation process. See e.g., D.P.U. 86-36-G, pp. 33-35, 39, 49 (1989).

In its Order, the Department sought comments on the proposed regulatory structure in such areas as the conflict between the goal of flexibility and the obligation of reviewability, the scope of negotiations by electric companies and project developers in the development of a resource plan, the use of a settlement process and a self-scoring ranking system, a realistic time frame for the four-phase IRM process, and a possible alternative framework for small electric companies. Id., pp. 73-77.

The Department also determined that each electric company would be required to include an environmental externality component in its all-resource solicitation evaluation criteria. Id., pp. 82-83. The Department proposed that all Massachusetts electric companies use a uniform environmental externality method in their request for proposals ("RFP") criteria. Id., pp. 86-87. The Department also identified three specific options for including environmental externalities and sought comments on the propriety of adopting a uniform method to account for such externalities. Id., pp. 88-89. Other areas in which the Department sought comments were the implementation of a transitional policy, methods to ensure aggressive pursuit of cost-effective resources, and the appropriate mechanism to eliminate financial disincentives regarding cost-effective investments in C&LM programs. Id., pp. 104, 114-115, 118.

To allow interested persons the opportunity to discuss issues raised by the proposed regulations, four technical sessions were conducted in January 1990. The technical sessions, jointly held by the Department and the EFSC on January 10, 17, 24, and 31, were designed to discuss the proposed regulatory structure and to promote an informed exploration of possible modifications to improve the structure. Following the technical sessions, written comments were received by the Department on February 23, 1990. Public hearings on the proposed regulations were jointly held by the Department and the EFSC on March 5, 6, 7, and April 17, 1990. Additional comments were received on May 10 and May 18, 1990.

The Department wishes to express its appreciation for the active participation of interested persons and the helpful comments received in this extensive investigation. These comments have been thoroughly reviewed and carefully considered by the Department in formulating these final regulations.

The final regulations attached to this Order are based on the Department's proposed regulations and have been modified, improved and clarified in light of the many comments received. Because of the extensive description of the rationale for the proposed regulations contained in the previous Department Orders in docket number D.P.U. 86-36, we will not repeat and summarize all aspects of the regulations. In this Order, we address only those areas in which major changes were proposed and considered in this final phase of this proceeding. Also, as in the past, we note that it is impossible to describe in detail all of the comments that have been filed in response to the proposed regulations. While we have considered all comments submitted, in the Order we will discuss comments in the context of the major issues addressed in the Order.

II. IRM STRUCTURE

A. Host Utility Participation

In D.P.U. 86-36-G, the Department determined that "electric company participation in the all-resource solicitation is desirable, necessary and consistent with the public interest." Id., p. 35. During the course of these proceedings, several persons submitted further comments on whether a utility should be permitted or allowed to participate, or be prohibited from participation, in its own solicitation process. Most commenters support a position consistent with the Department's prior decision. However, Wheelabrator Technologies ("Wheelabrator") and Representative Lawrence Alexander, citing anti-competitive concerns, recommend that a host utility be precluded from participating in its own solicitation (Wheelabrator Comments, 2/23, p. 2; Rep. Alexander Comments, 5/18, p. 3). Similarly, the Division of Energy Resources ("DOER") proposes that a host utility should be precluded from developing projects in its own service territory for at least the first few rounds of the IRM process (DOER Comments, 2/23, p. 4).

The Department's proposal in D.P.U. 86-36-G was based on a careful weighing of the positive and negative implications of a utility's participation in its own resource solicitation. While the concerns voiced by commenters in this proceeding deserve serious consideration, they are not beyond those considered in the Department's earlier decision. Id., p. 35. These comments continue to persuade us that the balance we struck in the proposed regulations is appropriate, given limited modifications to other aspects of the regulations, as presented infra. Accordingly, the Department finds that electric company participation in the solicitation process is appropriate and necessary, and the final regulations are unchanged on this issue.

B. Committed Resources

1. Background

Under the proposed regulations, a committed resource is conceptually any existing or planned, supply- or demand-side resource that has, in effect, a guaranteed spot in an electric company's resource portfolio during a single cycle of the IRM process. Resources deemed committed would not be subject to replacement by new resource alternatives obtained through the IRM competitive solicitation process. By contrast, any resource that is without committed status would be subject to possible replacement by a more cost-effective, or otherwise more desirable, resource identified in the solicitation process.

Again from a conceptual standpoint, the costs associated with any supply- or demand-side resources are separable into those that are avoidable and those that are unavoidable. For example, existing utility-owned generation generally has avoidable costs (for example, energy, variable operating costs, future capital additions) and unavoidable costs (for example, sunk capital costs in rate base); similarly, depending on the provisions of their particular contracts, third-party power purchase agreements for dispatchable units may also have avoidable costs (for example, fuel costs where the contract specifically provides for the pass-through of such costs to ratepayers) and unavoidable costs (for example: dollar-per-kilowatt capacity payments, whether or not tied to plant availability, as set forth in the contract; or, all contract payments for a must-run unit without any buy-out provisions in the contract; or, contract-buyout costs where the contract specifically provides for them).

In general terms, the replacement of capacity and energy from a particular resource may be warranted if the costs that could be avoided if that resource were eliminated from a company's resource portfolio (i.e., its avoidable costs) exceed the total costs of a new, replacement resource. From a resource provider's standpoint, the occasional replacement of a resource through the solicitation process can result only in the elimination of revenue streams attributable to the avoidable costs associated with that resource. Resource providers will remain entitled to the fixed revenue streams to which they may be contractually entitled, and which comprise the unavoidable costs of a displaced resource.

2. Comments on Committed Resources

The three electric companies that commented on the subject of committed resources favor granting committed status to existing generation, existing purchases from other utilities and third-party QFs and IPPs, resources whose cost-recovery terms have been preapproved by the Department, and utility-provided C&LM programs.[4] In this vein, Western Massachusetts Electric Company ("WMECo") offers a detailed definition of committed resources (WMECo Comments, 2/26, pp. 33-34). Boston Edison Company ("BECo") also supports a broad definition of committed resources (BECo Comments, 2/23, pp. 17-18). Massachusetts Electric Company ("MECo") recommends that the IRM process focus on new resources needed for the future and that it not become a forum for the reopening and relitigation of existing or approved resources (MECo Comments to the EFSC, 8/17, p. 3).

The Conservation Law Foundation ("CLF") emphasizes that the IRM regulations "should permit and encourage the retirement and replacement of existing generating units where that course of action is socially cost-effective, taking into account proper ratepayer compensation for the truncated revenue stream otherwise to be expected from the unit" (CLF Comments, 2/26, p. 41). These concerns are reflected in the comments of the Attorney General of the Commonwealth ("Attorney General") (Tr. II, p. 100). As presented in Section II.D.2, infra, CLF

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4 The Department notes that on August 27, 1990, several utilities and other parties filed comments with the EFSC, in which such commenters addressed the treatment of committed resources in the EFSC's proposed regulations. We recognize the EFSC's procedural schedule calls for public hearings on this issue starting September 5, 1990. The discussion hereinafter assumes that the EFSC will consider all such written and oral comments when it finalizes its regulatory treatment of committed resources.

also recommends treating preapproved C&LM resources in a manner that would, in essence, render them committed (CLF Comments, 2/26, pp. 10-14).

Massachusetts Citizens for Safe Energy ("MCSE") seeks to have all existing and potential future resources subjected to ongoing scrutiny via inclusion in the IRM process. Massachusetts Public Interest Research Group ("MassPIRG") adopts a similar position, with the exception that it maintains that, at least initially, new demand-side projects should not displace utility programs (MassPIRG Comments, 2/26, p. 10; 5/7, pp. 3, 13-14). Comments from Representative Alexander supported MassPIRG's position (Rep. Alexander Comments, 5/18, p. 19).

DOER proposes a process whereby the companies would propose and the Department/EFSC would establish the committed inventory for each company during Phase I in each solicitation round, and nothing would be assumed committed for more than one round (DOER Comments, 2/23, p. 13).

3. Analysis and Findings

Although a range of comments were received regarding the definition of committed resources, the debate appears to revolve more around practice than theory. While some commenters have emphasized the need to be able to subject expensive, unreliable, or environmentally unacceptable resources to the scrutiny of competition, no commenters contend that uneconomic resources should not be displaced.[5] Consequently, at issue is the mechanism by which the occasional, potentially uneconomic or otherwise unacceptable resource may be removed for analytic purposes from a utility's committed resource portfolio and then exposed to competitive ranking with, and possible replacement by, new resources procured through the IRM process.

The Department fully appreciates the importance of stable planning and financial environments to utilities and their suppliers. On several occasions during these proceedings we have communicated our intent, as a general practice, to exclude existing and planned resources from the competitive solicitation process in order to preserve the integrity of utility resource portfolios already in place. Preservation of a stable planning environment remains an objective of the Department and of the IRM regulations. However, there may be rare occasions when economic, environmental, or other relevant attributes of a resource may justify the use of the competitive solicitation process to determine the reasonableness of replacing that resource in a utility's resource portfolio. The Department finds that such an evaluation may properly occur within the following framework. However, the Department recognizes that

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5 As CLF indicates, resources are only uneconomic on a "to go" basis because utilities and independent resource providers would have to be compensated for sunk costs or any contractually obligated revenue streams (CLF Comments, 2/26, p. 41).

the full development of this framework is largely dependent on the EFSC's final Order and regulations.

The IRM framework anticipates that all existing and planned resources in a utility's resource portfolio shall be treated as committed in the solicitation process, unless the EFSC makes a specific finding in its Phase I Order identifying an existing resource as a candidate for possible replacement. Such a finding may result from either of two processes. First, using Phase I filing data[6] and any other relevant information, in conjunction with the criteria by which a utility proposes to evaluate Phase II proposals, nothing would prevent a utility from proposing and attempting to demonstrate in its Phase I filing that certain existing resources may warrant replacement by a new resource. The EFSC, if it finds the company's presentation persuasive, may so indicate in its Phase I Order. Accordingly, that utility's resource need, as identified by the company and if confirmed by the EFSC, would reflect the exclusion of any potentially uneconomic or otherwise marginal resource from the company's committed resource portfolio.[7] On

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6 With its Phase I filing, each utility shall submit specific information regarding price and non-price factors, and regarding future avoidable and unavoidable costs, for each existing and planned resource in its resource portfolio, as defined and prescribed by the EFSC's applicable IRM regulations.

7 The Department finds that each electric company must, in its Phase I resource plan, identify the best mix of

the other hand, the EFSC may reject the company's recommendations with regard to resources that are candidates for replacement; in this event, such resources would remain as committed resources.

Second, while the EFSC's proposed regulations contemplate that existing resources will enjoy a presumption of being treated as committed during each solicitation cycle, we expect that this presumed status may be challenged in Phase I by any party to an IRM proceeding, or by the EFSC on its own initiative. Consequently, the EFSC occasionally may be presented with, or on its own initiative discover, evidence that the cost, performance, environmental, or other characteristics of an existing resource warrant requiring a utility to expose that resource's capacity and avoidable costs to analysis to determine whether it would be economical to replace that resource with other resources proposed in the competitive

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resources by which it would propose to meet its obligations to ratepayers. Regarding any existing resource in a company's resource portfolio, it is assumed that each company will reflect any improvements that should be made pursuant to its ongoing obligation to provide electricity at the least total cost and consistent with other important factors set out in its Phase II resource evaluation criteria. Consequently, modifications to existing utility resources will not be permitted subsequent to the Phase I submittal of an initial resource portfolio. Electric companies must evaluate existing resources that have been identified in a Phase I EFSC order for possible replacement on an "as is" basis, that is, with no change to the price and non-price terms specified in the company's Phase I filing.

solicitation process.[8] Accordingly, the EFSC may find in its Phase I Order that certain existing resources should be excluded from a company's committed resource portfolio beyond any proposed for such treatment by the company, and therefore may make a corresponding adjustment to the company's resource need. It is anticipated, subject to the EFSC's final Order and regulations, that only a very small set of existing resources, if any, with cost and other characteristics that are particularly unattractive, would be so distinguished by the EFSC, for reasons presented infra. However, in such instances, the electric company would be required in Phase II to analyze resource mix options that assume that the noncommitted resource is not part of the resource mix, along with analyzing other resource mixes that do include that resource.

The Department finds that there are two necessary components to the decision by which an existing resource may be displaced in the IRM process. First, such action must be supported by a proper investment analysis that weighs the future avoidable costs associated with the resource in question against the total costs of the displacing resource, treating as "sunk" any unavoidable costs. Second, assessing the value of any

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8 As described infra, such analysis would essentially compare the avoidable costs of the existing resource with the total cost of a new resource, thus ensuring that replacement would occur only after recognizing as "sunk" the unavoidable costs of existing resources.

particular resource requires a comparison to the alternatives from the standpoint of other relevant factors identified in a company's Phase II resource evaluation criteria. Such factors could include the development status, or the operational character of a generating facility or demand-side program; they should include the impacts of environmental externalities, as discussed in Section III, infra.

Two points must be reemphasized. First, if any generating facility or resource option is displaced through the IRM process, the financial obligations of a utility or its ratepayers, or both, to the provider of that resource must be met in full. For instance, cost recovery for any utility investment that has been placed into rate base would continue under the traditional cost-of-service framework. Similarly, the owner of any utility resource that has been preapproved by the Department, or of any third-party resource regarding which a utility's power purchase agreement has been approved by the Department, shall be entitled to full recovery of any revenue streams to which it is entitled under the specific terms of its power sales contract. This means specifically that for a power purchase contract to have any avoidable costs, there would have to be either explicit contract-buyout provisions in the contract, or a clear indication in the contract itself that some portion of the payments (for example, capacity payments) were designed expressly to cover all project investment costs. Absent these contract elements, there would be no avoidable

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IMAGE EVALUATION TEST TARGET (MT-3)

150mm

6"

1

IMAGE EVALUATION TEST TARGET (MT-3)

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IMAGE EVALUATION
TEST TARGET (MT-3)

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IMAGE EVALUATION TEST TARGET (MT-3)

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costs assumed in the analysis to determine whether the project should be replaced with a new resource. Any existing and approved contract, or any new contract that lacked such provisions but was still approved by the Department, would be treated in this manner in the IRM process.

Second, it is expected that replacement of existing resources will be rare. Assuming that the non-economic attributes of two competing resources are generally equal, before a new resource can replace an existing resource, not only must the cost of the new resource be demonstrated to be lower than that of the resource targeted for displacement, it must be sufficiently low to make incurring the cost of the new resource plus supporting any unavoidable revenue stream associated with the resource targeted for replacement more attractive than the total costs that would be incurred if the targeted resource were simply left in the utility's resource portfolio.

C. Filing Requirements For Projects Included in a Utility's Initial Resource Portfolio

The Department's proposed regulations outlined Phase I and Phase II utility filing requirements that reflected an effort to balance the need to make sufficient information available to the public to prevent self-dealing, and the desire to ensure that utility-sponsored projects not be put at a competitive disadvantage. D.P.U. 86-36-G, p. 37. During the course of these proceedings, further comments were received regarding the nature and timing of information that utilities should disclose regarding their own new resource proposals in the IRM process.

The utility commenters generally sought to minimize the quantity and types of information regarding their own resource proposals that they might be required to submit for scrutiny during the Phase I process. BECo maintains that its Phase I description of uncommitted resources should be limited to only a generic description of its options (Tr. II, pp. 40, 42-43). BECo expressed concern that disclosure of price or all non-price factors relating to its own projects would provide a significant competitive advantage to other bidders (BECo Comments, 2/23, pp. 17-19; Tr. I, p. 205). The National Independent Energy Providers ("NIEP") suggests that utilities may include third-party resources as part of their resource plan and that there would be an interest in minimizing the proprietary information that would have to be disclosed (Tr. II, pp. 125-126). WMECo agrees with both BECo and NIEP that only limited non-price information should be provided regarding all of the options included in a utility's resource portfolio (WMECo Comments, [illegible], p. 9).

The Conservation Consortium proposes that, although utilities should not be required to divulge their bid prices in Phase I, a reference price should be provided by which developers could construct informed bids (Conservation Consortium Comments, 2/23, pp. 3-4). SESCo, Inc. ("SESCo") also supported publication of a reference price (Tr. I, p. 128).

At the other end of the spectrum are commenters such as the Attorney General, Representative Alexander, MassPIRG, and MCSE, who contend that it is necessary for utilities to reveal all price and non-price information to prevent them from using their dominant positions to destroy an infant competitive market (Tr. II, pp. 73-74; Rep. Alexander Comments, 5/18, pp. 3-4; MassPIRG Comments, 2/26, pp. 6-7; MCSE Comments, 2/23, p. 1).

Even considering the concerns reiterated by several commenters on this matter, the Department still finds the balance struck in the proposed regulations to be a reasonable one. Consequently, in order to minimize any competitive disadvantage to utilities that may result from revealing their proposed projects before the time when other resource developers would submit their proposals, the Department finds that it is not appropriate to require utilities to submit price or other cost information regarding new projects in their initial resource portfolios when filed at the start of Phase I. Rather, such information shall be submitted at the time that other developers submit their proposals in Phase II. Accordingly, the regulations require each host utility to submit to the Department the price and other relevant cost-recovery information applicable to its new resource proposals by the close of business on the day before that on which third parties must submit their proposals in Phase II; further, such information shall be submitted before any utility initiates its review of third-party proposals. All other data regarding host utility projects shall be filed in Phase I, as prescribed by the regulations.

An important issue has been raised concerning the effects that full disclosure in Phase I of the details pertaining to a third-party project proposed by a utility as part of its resource portfolio. Both BECo and NIEP have correctly pointed out that such Phase I disclosures may disadvantage the developer of such a third-party project vis-a-vis other developers in that particular solicitation process and in the market generally.

Once again, the Department must balance the objective of fostering the benefits of competition in the wholesale generation market with that of controlling utilities' ability to influence that market unduly. The Department finds that, if a utility has no ownership interest in a third-party project that has been proposed as part of its initial resource portfolio, then that project is in no substantial way different from those that may be proposed later by other developers in Phase II, to be included as part of the utility's eventual award group. Therefore, no significant anti-competitive effects would be anticipated if the details regarding such third-party projects were excluded from the Phase I process.

Accordingly, the Department finds that if a utility proposes as part of its initial resource plan a third-party project in which the utility has no direct or indirect ownership interest, the utility need only provide limited information as to the nature of the project in its Phase I filing. As is prescribed in the regulations, such information shall include the following: the name and address of the owner and operator of the project; a brief description of the project including the nature of the technologies employed; the nameplate capacity (if appropriate); the anticipated capacity and energy purchase, or capacity and energy savings; location; fuel type (if appropriate); development or operational status; and, the anticipated operational date.

If, however, a host utility has or anticipates having an ownership interest in any project being developed by a third party, all filings pursuant to the all-resource solicitation shall be in keeping with those required for proposed resources that would be fully owned by a host utility.

D. Including C&LM Resources in the All-Resource Solicitation

1. Introduction

In D.P.U. 86-36-G the Department proposed that electric companies include both C&LM and supply resources in their all-resource solicitations, and offered electric companies the flexibility to issue either joint, or separate but parallel, solicitations to procure the different resource types. The Department proposed requiring electric companies to integrate demand- and supply-side resources on an equivalent basis by using the same general selection criteria (e.g. price, quantity, characteristics of the output or savings, reliability, external costs) when selecting the final quantity and mix of C&LM and generation technologies. In addition, because the Department found that the private C&LM market may not be sufficiently mature to identify and develop all economic C&LM opportunities, the Department's proposed regulations required electric companies to propose cost-effective, comprehensive C&LM programs for each sector and subsector in its initial resource portfolio. Id., pp. 55-56.

Commenters have raised two fundamental concerns about how the proposed regulations incorporate C&LM in an all-resource solicitation. First, some question the extent to which private C&LM developers should be allowed to compete directly against host electric company C&LM programs. Second, many parties express concern that open competition for C&LM savings will promote cream-skimming by private C&LM developers.

2. Electric Companies' C&LM Programs

CLF argues that it will be difficult to reconcile a C&LM bidding system with the electric companies' collaborative programs. Specifically, CLF claims that it will be difficult to establish boundaries between electric companies' efforts and those of the private C&LM developers because the collaborative programs are already comprehensive and C&LM does not naturally lend itself to piecemeal development. It also contends that only electric companies can provide a long-term approach to maximizing C&LM savings that will be comprehensive across all customer types and end-uses, will exercise sufficient quality control, and will provide comprehensive monitoring and evaluation across all programs (CLF Comments, 2/26, pp. 10-12). CLF suggests that the Department reaffirm the leading role of electric companies in developing C&LM and not require companies to solicit C&LM proposals in the all-resource solicitation. Instead, it recommends that the Department encourage electric companies to use a competitive bidding process only to subcontract for specific services and goods necessary to implement the electric companies' own C&LM programs. CLF proposes that the Department assess the results of the collaboratively designed C&LM programs over the next few years and then consider whether to open the all-resource solicitation to C&LM proposals (id., pp. 13-14).

MassPIRG and WMECo agree that the collaborative programs should somehow be protected from competition in the near term. However, they do not suggest that C&LM bidding is completely inappropriate in the near term. Instead, they recommend that third-party C&LM developers be allowed to supplement, rather than displace, utility programs if they can find any approaches to exceed electric companies' efforts (MassPIRG Comments, 5/7, pp. 13-14; WMECo Comments, 5/4, p. 19).

In contrast, third-party C&LM developers (Conservation Consortium, O'Connell Engineering ("O'Connell"), and SESCo) disagree that utility programs should be protected from competition. The Conservation Consortium argues that (1) utilities have not demonstrated an ability to provide cost-effective C&LM in the past, despite Department mandates to do so; (2) third-party developers can provide greater economic efficiency and a more secure resource supply, in the same way that QFs have; and (3) cream-skimming issues can be resolved with avoided cost proxies (Conservation Consortium Comments, 5/4, pp. 5-9). O'Connell and SESCo argue that the C&LM market is sufficiently mature to allow for open competition between all providers in order to promote economic efficiency (O'Connell Comments, 3/6, pp. 2-4; SESCo Comments, 2/25, p. 2).

In D.P.U. 86-36-D, the Department, recognizing the need for direct utility involvement in C&LM, approved the utilities' embarking on a collaborative project specifically for the purpose of expediting the design and implementation of comprehensive, cost-effective C&LM programs, which the market was not adequately structured to accomplish. Id., p. 3. In D.P.U. 86-36-F the Department found that electric companies are in a unique position to identify and implement cost-effective C&LM and allowed electric companies to request preapproval status for their C&LM programs, in order to allocate the risks and rewards for such resources between an electric company and its ratepayers. Id., pp. 18, 27-31. The Department has recently preapproved cost-effective C&LM programs for four electric companies in the Commonwealth. See Massachusetts Electric Company, D.P.U. 89-194/195; Western Massachusetts Electric Company, D.P.U. 89-260; Cambridge Electric Light Company and Commonwealth Electric Company, D.P.U. 89-242/246/247.

The Department finds that preapproved C&LM programs can appropriately balance risks and rewards, while encouraging the development of comprehensive cost-effective C&LM programs. The Department agrees with CLF that private C&LM developers could undermine some of the electric companies' efforts because of the potential for piecemeal development approaches and those private developers' internal incentives for cream-skimming. The Department therefore finds that electric company C&LM programs that have been preapproved by the Department should be allowed sufficient opportunity to be implemented by the companies.[9]

Nevertheless, the Department does not wish to foreclose the opportunity for private C&LM developers to provide C&LM resources, if those developers can offer resources that exceed electric company efforts (e.g., capture non-participants, introduce new technologies, or serve additional end-uses that are not addressed by an electric company's preapproved programs). Accordingly, the final regulations require that, in the all-resource solicitation, electric companies accept and evaluate C&LM proposals from third-party C&LM developers.

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9 This is the same treatment afforded any contracted-for resource. The Department notes that although we encourage collaborative efforts between all interested parties, it is the Department's preapproval of C&LM programs, rather than the fact that they have been collaboratively designed, that gives a utility's C&LM program special, protected status as committed resources under these new rules.

Electric companies are required to define the boundaries of their preapproved programs[10] during the Phase I review of their initial resource portfolio, and will have the option to reject C&LM proposals that are redundant with their own preapproved programs.

Such proposals may include proposals for fuel-switching that electric companies would have to evaluate in Phase II according to the Department-approved resource evaluation criteria and cost-effective methodology.

Through our preapproval review process, the Department will periodically reassess whether an electric company's preapproved C&LM programs continue to meet our standards for preapproval status.[11] If the Department determines that a program is no longer meeting its proposed performance targets, or is otherwise not optimally designed, we will notify the EFSC of our decision and will recommend that the program no longer be exempted from competition in the all-resource solicitation.[12]

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10 This must include, at a minimum, the customers the programs will reach, the technologies that will be provided, the end-uses covered, and the geographic regions included and excluded by each program.

11 Moreover, in future preapproval Orders, the Department intends to make more explicit findings about the timeframes over which the companies' C&LM programs are deemed to be approved.

12 Of course, any conservation measure that has been installed and is providing cost-effective savings will retain its committed resource status and will continue to be exempt from competition.

3. The Risk of Cream-Skimming

Many of the C&LM advocates express concerns that C&LM bidding will promote cream-skimming by C&LM project developers (CLF Comments, 2/26, pp. 7-9; MassPIRG Comments, 2/26, p. 8; DOER Comments, 2/23, pp. 14-15; Rep. Alexander Comments, 5/18, pp. 17-18; MCSE Comments, 2/23, p. 2). These commenters argue that C&LM is fundamentally different from supply-side resources because different amounts can be provided at different costs. They argue that if price is a factor in selecting the award group, developers will have an incentive to cream-skim in order to propose a low price, which would place the most comprehensive programs (i.e., those that may be more expensive, but still cost-effective) at a disadvantage. CLF argues that it is not possible to eliminate the threat of cream-skimming through the selection criteria because this would require "an advanced detailed knowledge as to what specific technologies and technology bundles represent maximum cost-effective efficiency implementation for any given facility type or cluster of facilities." CLF claims that this knowledge does not presently exist (id.).

SESCo, O'Connell, and the Conservation Consortium argue that cream-skimming will not be a problem. O'Connell asserts that C&LM developers will respond to appropriate selection criteria that place value on avoiding lost opportunities. It also claims that lost opportunities may not be such a problem because it may be possible to pursue them in the future if the economics change

(O'Connell Comments, 5/6, pp. 2-4). The Conservation Consortium argues that cream-skimming problems can be resolved by means such as avoided-cost proxies (Conservation Consortium, 5/4, pp. 5-9). SESCo argues that C&LM is sufficiently mature to be able to compete directly with supply-side options (SESCo Comments, 2/25, p. 2).

The only electric company that addressed the cream-skimming issue was Fitchburg Gas and Electric Light Company ("Fitchburg"). Its main concern is that open bidding would not result in a coordinated C&LM implementation across all customer classes because developers would focus on the customers with the least expensive C&LM savings (Fitchburg Comments, 2/23, p. 7).

Commenters put forward several proposals for minimizing cream-skimming in a competitive bidding context. DOER and Representative Alexander recommend that host electric companies require developers to propose "supply curves" for conservation measures. This would require C&LM project developers to identify the full range of conservation technologies available for specific applications at the various levels of cost, on a measure-by-measure basis. In this way, the host utility could select those technologies that it believes will offer the most comprehensive, cost-effective C&LM savings (DOER Comments, 2/23, pp. 14-15; Rep. Alexander Comments, 5/18, pp. 17-18). SESCo and MCSE recommend that the Department require host electric companies to release a "reference price" for demand and supply project developers to use as a benchmark for determining the price range over which the utility expects to purchase power. This reference price could be based on avoided costs. C&LM developers that bid projects above this price would get credit on other non-price factors if the proposed C&LM programs are especially comprehensive. C&LM developers that bid below the reference price would have to demonstrate that they are not creating lost opportunities (SESCo Comments, 5/8, pp. 6-7; MCSE Comments, 2/23, p. 2).

The Department agrees that C&LM bidding may create a risk of cream-skimming because of the incremental nature of C&LM implementation and cost. However, the Department finds that host electric companies have a variety of means for reducing the problem of cream-skimming. Some of the options that, separately or combined, could help reduce cream-skimming include: holding separate but parallel solicitations; developing selection criteria to detect cream-skimming; using supply curves or reference prices; and negotiating to ensure that cream-skimming is minimized. The Department finds that electric companies must include method(s) to evaluate and penalize cream-skimming in their RFP criteria. Rather than foreclose any option for accomplishing this objective at this time, the Department will review proposed methods on a case-by-case basis within the IRM process.

E. Phase II Project Evaluation, Modification and Selection

1. Introduction

In D.P.U. 86-36-G the Department proposed the following structure for evaluating, modifying and selecting resources identified in each electric company's solicitation:

1. All resource proposals would first be screened to make sure they surpass Department-approved thresholds. Id., p. 41. Proposed 220 CMR 10.04(3)(a).
2. Each project would then be ranked based on the scoring system approved in Phase I. The scoring system need not be self-scoring; however, the Companies would be required to have weights for each category of criteria and to explain how each criterion would be applied to evaluate individual project proposals. Id., p. 42. Proposed 220 CMR 10.04(3)(c).
3. Projects would then be reranked to reflect the most beneficial portfolio of resources. This optimization phase was added to allow electric companies to account for interactive effects, redundancy in C&LM programs, and drastic changes in fuel prices or other relevant factors that changed since the issuance of the RFP. Id., p. 44. Proposed 220 CMR 10.04(3)(d).
4. Finally, electric companies would be able to negotiate both price and non-price factors with project developers as long as any changes made during negotiation improve each project with respect to the overall portfolio of projects. In the proposed regulations, companies would be required to give each project in the negotiation group the opportunity to improve its overall score. The negotiation group is defined as 130 percent of the size, in megawatts, of the largest resource need projected in any one of the first ten years of the demand and committed supply forecasts that were approved in Phase I. Because of concerns with potential self-dealing, an electric company would not be allowed to negotiate with itself; it could not change either the price or non-price factors of its own projects. Id., pp. 45-50. Proposed 220 CMR 10.04(3)(e).
5. Companies would then select an award group based on their optimization and negotiated changes that should be as close as possible to 100 percent of the size of the resource need. The companies would submit this final resource mix,

along with the initial ranking and justification for any deviations, to the Department for our review. Id., p. 48. Proposed 220 CMR 10.04(3)(f).

2. Summary of Comments

There is a general consensus among all commenters that the Department should allow electric companies to reoptimize initially ranked projects to account for interactive effects between resources, redundant resources, and drastically changed circumstances that would justify deviation from the initial resource mix. There is also substantial agreement among the commenters that the Department should allow electric companies to negotiate with project developers to improve individual projects. However, commenters disagree both on whether the Department should eliminate self-scoring in the initial ranking process, and on the size of the group with which the electric company would negotiate.

a. Self-Scoring

About half the commenters argue that self-scoring should be required. Many reason that the optimization and negotiation steps that follow the initial ranking add too much flexibility without a self-scoring system (Tr. II, p. 68; MassPIRG Comments, 2/26, p. 7; Conservation Consortium Comments, 2/23, pp. 3-4; Citizens Conservation Comments, 2/28, p. 5). Others argue that self-scoring is necessary to provide greater information to potential bidders, particularly the trade-offs between various factors (SESCo Comments, 2/25, pp. 1-3; PG&E/Bechtel Generating Company ("PG&E/Bechtel") Comments, 2/28, pp. 6-7; O'Connell

Comments, 3/6, pp. 6-7; Citizens Conservation Comments, 2/28, p. 5; MCSE Comments, 2/23, p. 2). Wheelabrator argues that if utilities are allowed to participate in their own RFPs, then self-scoring is "absolutely necessary" to protect against self-dealing (Wheelabrator Comments, 2/23, p. 3).

Other commenters contend that the need for flexibility in the selection process outweighs whatever advantage may be gained through a rigid, self-scoring approach. BECo maintains that the Department has more than sufficient regulatory oversight of the process to protect against self-dealing, and therefore implies that a rigid self-scoring system is unnecessary (BECo Comments, 2/23, pp. 12, 24-25). MECo claims that self-scoring prejudices the process, and argues that the market should determine the relative weights (MECo Comments, 3/8, p. 16). Cambridge Electric Light Company and Commonwealth Electric Company (collectively "ComElectric") argue that self-scoring should be optional (ComElectric Comments, 5/4, p. 9-10). WMECo agrees that self-scoring should be optional for all or part of a company's RFP, and maintains that, as long as potential bidders understand the evaluation criteria, weighting factors, and optimization method, self-scoring is not necessary (WMECo Comments, 2/26, p. 24; Q-Sec. III-1, p. 1). DOER, the only non-utility commenter to support the elimination of self-scoring in its comments, argues similarly to WMECo that, as long as the scoring system is "clear, as precise as possible, transparent and reviewable," self-scoring need not be required (DOER Comments, 2/23, p. 8).

On other matters relating to scoring, Altresco Financial Inc. ("Altresco") encourages the Department to include a request for qualifications ("RFQ") phase to eliminate poor proposals from competing in the RFP process (Altresco Comments, 2/23, p. 1). Under an RFQ process, projects would be eliminated from consideration if they didn't meet certain minimum criteria (e.g., a project proposed by a completely inexperienced developer without financial backing). PG&E/Bechtel also argues for such RFQ thresholds, but only for facilities with a capacity of over 50 megawatts ("MW") (PG&E/Bechtel Comments, 2/27, p. 7). SESCo urges that the Department not allow companies to use "the bludgeon effect of steep thresholds" (SESCO Comments, 5/8, pp. 8-9).

The Department concurs with many of the commenters that the scoring system used to develop the initial ranking of projects must be clearly articulated so that potential bidders understand the trade-offs both between different criteria (e.g., between dispatchability and fuel diversity) as well as within a particular criteria (e.g., high-priced projects will rank lower than low-priced projects). Similarly, the criteria and its application must be sufficiently detailed to allow the Department to evaluate an electric company's initial ranking. The delicate balance between flexibility on the one hand, and protection from self-dealing and reviewability on the other must be maintained throughout the entire process.

Given the Department's objectives, we find that the elimination of the required self-scoring mechanism present in our existing QF regulations will not unduly tip the balance of the entire process towards flexibility. Indeed, because the new solicitation process will be more comprehensive and will encompass all resources, a rigid self-scoring system may be an inappropriate method of evaluating the relative qualities of the wide range of resource options that will be involved. Accordingly, the Department finds that self-scoring should not be required. Each company will, however, be required in Phase I to select and justify a weight for each criterion along with a detailed qualitative description of how it will apply the criterion to the range of likely projects. For many criteria, this will mean specific scoring values will be explicitly defined. In this sense, developers will continue to be able to self-score to a significant degree. During Phase II, the companies will use the scoring system approved in Phase I to assign a point score under each individual criterion and to add all the scores of each individual criterion together to form a total score for each project.

The Department does not find at this time that an RFQ process per se at the front-end of the RFP process is necessary. The administrative burden associated with an added layer of review outweighs the benefits to be realized from such a process. Rather, the Department will require companies to develop and incorporate thresholds for certain project or developer qualification criteria in their RFP, with the thresholds set high enough to prohibit consideration of poor projects while not eliminating projects that may be beneficial to ratepayers, thus serving the same purpose of an RFQ.

b. Optimization

Since only positive comments were received about the Department's proposed optimization phase, and in light of the concern raised by MIT (MIT Comments, 3/13, p. 2) that projects ultimately must be analyzed in the context of an electric company's total resource portfolio rather than on a head-to-head basis, the Department finds that the optimization step is appropriate and retains it in these regulations.

c. Negotiation

Although commenters generally support including some type of negotiating process, different concerns are expressed regarding both the size of the negotiating pool and what issues would be eligible for negotiation. The Attorney General and O'Connell comment that negotiation could lead to unrealistically low initial bids (Tr. II, p. 71; O'Connell Comments, 3/6, pp. 1-2). Fitchburg argues that negotiations should not be allowed to change the initial proposals radically (e.g., major changes in site, fuel type, or technology) (Fitchburg Comments, 2/23, p. 9). NIEP expresses concern that the opportunity to change proposals and thereby alter RFP conditions in the middle of the process might be unfair to the developers of proposals not included in negotiations (NIEP Comments, 2/22, p. 5).

O'Connell and ComElectric state that the Department's 130 percent negotiation group cut-off seems reasonable (O'Connell Comments, 3/6, pp. 1-2; ComElectric Comments, 5/4, p. 8). WMECo and Eastern Edison Company ("EECo") accept the 130 percent minimum negotiating group size, but advocate allowing electric companies to negotiate with more projects up to the total MW response at their own discretion (WMECo Comments, 5/4, p. 17; EECo Comments, 5/4, p. 3). MECo argues that the cut-off should be eliminated and that companies should be allowed to negotiate with any or all developers (MECo Comments, 2/23, p. 12). DOER also recommends allowing each electric company to determine the size of its negotiating group (DOER Comments, 2/23, pp. 7-8).

The Department finds that the opportunity for negotiation appropriately provides the flexibility necessary to improve the quality of the final mix of projects. The Department views the negotiation process as an opportunity for developers to improve projects. As proposed in the regulations, all aspects of the originally bid project would be open to some modification; however, the Department does not contemplate that such negotiations will result in radical transformations such as major changes in site, or changes in technology or fuel type. Also, to reduce the potential problems with self-dealing, host electric companies and their affiliates proposing projects will not be permitted to change the specifications of their original bids in order to gain entry into the award group.

The Department does not agree with MECo's suggestion to allow companies complete discretion in selecting the set of developers to negotiate with, because it would make the process administratively cumbersome to implement and review, and would undermine the integrity of the RFP process. For instance, if a company chose to negotiate with developers whose projects were ranked below others, while not negotiating with developers of higher-ranked projects, the Department would expect a series of appeals or objections from the higher-ranked developers who were not given the opportunity to negotiate an improved package. The Department considers it critical that, starting from the top of the optimized list of projects, all projects up to a certain point be allowed to improve their project proposal. Given the comments regarding the size of the negotiating group, the Department finds that electric companies will be permitted to select the size of their negotiating group, as long as that group is at least 130 percent of the size, in MW, of the largest resource need projected in any one of the first ten years of the demand and committed supply forecasts that were approved in Phase I, and that all projects up to the cut-off point (except those projects in which the company has a direct or indirect ownership interest) are given the opportunity to negotiate improvements to their projects.

F. Other IRM Structure Issues

1. Prefiling Settlement

In D.P.U. 86-36-G the Department proposed using a prefiling settlement process. Id., pp. 59-61. Proposed 220 CMR 10.03(4). The settlement process could be used to discuss and, where possible and appropriate, to resolve issues concerning the initial filing. The process as proposed would begin when the EFSC and Department would issue a joint Order of Notice, eleven weeks before the initial filing date. Within ten days from the joint Order, the Company would issue a notice and distribute a draft Phase I filing. A technical session would be held to explain the draft filing and establish the parameters of further settlement discussions. Any settlement or partial settlement reached by all or some of the parties would be filed as part of the Phase I filing. The Department and EFSC would review the settlement, and non-signatory parties would have the opportunity to address any issue included in it. Staff members of the EFSC and Department may participate in settlement discussions, but such staff members would not participate in the Department's or EFSC's review or in subsequent affiliated adjudications. Facilitation was also encouraged in the proposed regulations. Proposed 220 CMR 10.03(4)(c).

Commenters were generally positive about the use of a prefiling settlement phase. WMECo, for instance, argues that the process "could significantly streamline and reduce the litigious nature of the remainder of the IRM process" (WMECo

Comments, 2/26, Q-Sec. III-7, p. 1). MECo, while supporting the use of such a process, recommends allowing only four weeks for the process, to give the electric companies enough time to compile all the necessary information (MECo Comments, 2/23, p. 4).

However, some parties assert that such a process would effectively shut out public interest groups from the process. Representative Alexander argues that

> ...the process will disadvantage smaller intervenors, who may be "outgunned" in terms of legal and technical resources and staff time and may find themselves presented with a fait accompli agreed upon by the electric company, energy project developers, and/or government agencies before the filing has even been made.

(Rep. Alexander Comments, 5/18, p. 2). Both MassPIRG and MCSE agree with Representative Alexander and advocate using the additional eleven weeks for technical sessions, discovery and examination (i.e., an expansion of the time for Phase I) (MassPIRG Comments, 2/26, p. 9; MCSE Comments, 2/23, p. 3). CLF recommends allowing for the "recovery of expert and attorney fees by participants in the process who make a substantial contribution to the adjudicatory record or settlement ... who would otherwise be unable to participate actively" (CLF Comments, 2/26, p. 43).

The Department shares the commenters' goal of ensuring that meaningful participation in the IRM process be afforded public-interest groups and other participants who may not have adequate resources. We acknowledge that complex technical issues and legal proceedings may disproportionately burden parties with more limited resources. However, the Department does not agree that the inclusion of a prefiling settlement process will necessarily exacerbate this problem for such intervenors. To the contrary, if the process is properly managed, such intervenors should have greater access to technical expertise and a better opportunity to influence the actual Phase I filing and subsequent decisions by the EFSC and the Department than they might otherwise have if their opportunities for participation were restricted to the formal adjudicatory process. Furthermore, parties are not required to participate in the prefiling settlement process and need not acquiesce to any settlements reached in the process. Under the regulations, the adjudicatory process commencing with Phase I will remain open to all parties who have obtained intervenor status, thus preventing foreclosure of important issues.[13]

The Department finds that the potential advantages of a prefiling settlement process outweigh its potential disadvantages. Accordingly, subject to the EFSC's final regulations on the IRM regulatory framework (980 CMR 12.00), the prefiling settlement process proposed in D.P.U. 86-36-G is not

13 Parties that want to intervene must file a written request for intervenor status to the EFSC and the Department within ten business days of the publication of a company's Order on Notice.

changed in these final regulations. The Department rejects MECo's argument to shorten the process because companies should be able to prepare equally well for a prefiling deadline that commences eleven weeks before the actual filing as a four-week prefiling deadline as long as a company is given sufficient advanced notice.

The regulations explicitly encourage a facilitation process as a way to increase the opportunity for a meaningful and well-organized pre-filing settlement process. The Department notes that all expenditures prudently incurred by an electric company and relating to the use of outside facilitators and technical and legal expertise to assist non-utility parties to participate effectively in the process would be considered legitimate legal or planning expenses.

2. Solicitation Cycle Timeline

a. Introduction

In D.P.U. 83-36-G, the Department proposed extending the length of each solicitation cycle from 17 months (as initially proposed in D.P.U 86-36-F) to 20 months.[14] D.P.U. 86-36-G, p. 64. In addition, the Department proposed that each subsequent initial filing of an electric company would be made between 18 and 30 months after the most recently submitted

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[14] The 20-month timeframe does not include the prefiling settlement process.

filing. Id. In order to keep all participants on a tight review schedule, the proposed regulations stated that an electric company's initial filing submitted in Phase I and its resource plan submitted in Phase III would be deemed approved if decisions were not reached by the designated reviewing agency within the specified time limits. Id., p. 63.

b. Comments

Many comments were received regarding the proposed 20-month timeframe. DOER and the Attorney General comment that the proposed timeframe is optimistic, especially in regard to Phase III activities. DOER comments that to complete an adjudicatory process such as suggested for Phase III within three months, it will be necessary to structure procedures that allow for parties to obtain the requisite information, conduct cross-examination, and possibly put on witnesses in an expedited manner (DOER Comments, 2/23, p. 23). The Attorney General comments that the three months allowed for the Department review of the award group in Phase III is insufficient and suggests that the Department explicitly provide itself the authority to extend the period of the Phase III review upon a finding that additional time is necessary (Attorney General Comments, 2/23, p. 5).

ComElectric comment that the four months proposed for contract negotiation in Phase IV appears unrealistic given their experience with QF contract negotiations. They suggest that successive cycles be held 36 to 48 months apart to give the utilities a realistic opportunity to evaluate the performance of previous award groups and form more accurate assumptions for use in preparation of their next RFPs (ComElectric Comments, 5/4, pp. 10-12). WMECo comments that four months has been inadequate for the EFSC to perform lesser reviews. In addition, it has learned through its experience with bidding that dissatisfied bidders, through the appeal process, can add many months to a resource acquisition process (WMECo Comments, 5/4, p. 11). WMECo suggests that successive cycles be held 43 months apart to allow the utilities time to prepare better for the next cycle (id., pp. 4-5).

Some commenters argue that the process takes too long to allow for a reasonable resource acquisition process. MECo suggests running Phases I and II, and then Phases III and IV in parallel, shortening the solicitation cycle by eight months (MECo Comments, 2/23, p. 3). NIEP suggests that the time allowed for the submittal of RFPs in Phase II be shortened from four months to three months, and the time allotted for negotiations with third-party suppliers be shortened from four months to three months (NIEP Comments, 2/22, p. 8). New England Cogeneration Association ("NECA") suggests that the Department's review of the award group commence at the point where the company determines the initial ranking of the bids, shortening the process by three months (Tr. I, p. 105).

BECo and ComElectric comment that for the proposed regulatory structure to succeed, it must be integrated with other regulatory processes involved in the permitting and oversight of proposed generating plants (BEco Comments, 2/23, pp. 26-27; ComElectric Comments, 5/4, pp. 4-5).

c. Analysis and Findings

The Department continues to find that the 20-month period proposed in D.P.U. 86-36-G represents the best timeframe for a solicitation cycle.[15] To shorten the amount of time allotted for any of the phases would inhibit the ability of the Department and the EFSC to review the process, while a longer process would not be sufficiently responsive to the utilities' need to make resource decisions in a timely manner. The Department rejects MECo's suggestion to run Phases I and II in parallel (in effect, this would allow companies to issue an RFP which might be subject to substantial changes), but notes that the regulations do not preclude a company from proceeding in Phase III to negotiate and/or sign contracts with award group winners it believes will be approved by the Department. Of course, any signed contract would have to be conditioned on Department approval of the award group.

An electric company's initial filing submitted in Phase I and its resource portfolio submitted in Phase III will be deemed

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15 With the passage of legislation securing funding for the IRM process, the Department and EFSC have been granted sufficient resources to act within this timeframe.

approved if decisions are not reached by the designated reviewing agency within the specified time limits.

The Department also continues to find that each subsequent initial filing of an electric company will be made between eighteen and thirty months after the most recently submitted filing. The exact schedule will be determined by the Department and the EFSC. Once this schedule is announced, it will be strictly followed to provide electric companies and resource developers with sufficient certainty concerning timing which is essential to the practical requirements of project planning and development.

3. Resource Procurement Outside of the IRM Process

a. Introduction

In D.P.U. 86-36-G, the Department observed that the development of certain resource projects may not fit neatly into the all-resource solicitation time frames. Id., pp. 51-52. Given the cyclical nature of the solicitation process that spans two years, the Department found it necessary and appropriate to allow emergency and short-term purchases (i.e., purchases of less than two years in duration) outside of the all-resource solicitation process. Id. The proposed regulations also allowed for out-of-cycle purchases from supply-side resources whose capacity is less than five MW, or 1.0 percent of the host company's annual peak demand, whichever is lower. Proposed CMR 10.07(1)(a). In addition, we found that unanticipated changes in circumstances or the unanticipated development and availability of new technologies could make it beneficial to ratepayers to allow electric companies to take advantage of certain opportunities that may become available between solicitation cycles. Id.

D.P.U. 86-38-G proposed a case-by-case review of out-of-cycle purchases, with the electric companies bearing the burden of demonstrating that the proposed purchase is consistent with the provision of least-cost, reliable service, and that the purchase could not reasonably be accommodated within the solicitation cycle. Id., p. 52. The Department noted that this procedure should be viewed as the exception rather than the general rule, and that such resources would be approved only in circumstances in which the resources must be acquired immediately and the acquisition of the resources in question would clearly be beneficial to ratepayers. The Department sought comments on ways to preserve the integrity of the solicitation process while providing the electric companies and the development community with the flexibility that is needed to ensure that reliable, least-cost service is provided to ratepayers. Id.

b. Comments

The Department received comments that cover a wide spectrum of ideas concerning out-of-cycle purchases. Citizens Conservation opposes the acquisition of any supply-side resources outside of the solicitation process. It suggests that only demand-side acquisitions be allowed outside of the process

(Citizens Conservation Comments, 2/28, pp. 8-9). SESCo recommends that electric companies be allowed to acquire an out-of-cycle resource provided its term is no longer than the effective conclusion date of the next solicitation (SESCo Comments, 5/8, p. 32). MassPIRG suggests that a utility's Phase I filing explicitly address criteria for acquiring resources outside of the process. According to MassPIRG, the filing should contain action plans for responding to higher- and lower-growth scenarios and fuel prices, and the failure of committed resources to come on line (MassPIRG Comments, 2/26, p. 9). The Conservation Consortium, DOER, and MSCE urge the Department to allow purchases outside of the IRM process only when the project could not have been bid in the previous solicitation, is unlikely to be able to bid in the next solicitation, and the purchase satisfies least-cost criteria (Conservation Consortium Comments, 5/4, p. 3; DOER Comments, 2/23, p. 21; MSCE Comments, 2/23, pp. 3-4).

Some commenters recommend that joint-utility projects, such as Hydro-Quebec and "pool-wide" offering arrangements, be explicity identified as eligible for out-of-cycle purchase (WMECo Comments, 5/4, pp. 8-9; PG&E/Bechtel Comments, 2/28, pp. 8-9; ComElectric Comments, 5/4, p. 6; Tr. I, p. 107). Finally, some commenters recommend that all purchases that can be shown to be least-cost should be allowed outside of the solicitation process. Under this approach, the petitioning company would bear the burden of demonstrating that such purchases are in the best interest of ratepayers (BECo Comments, 2/23 pp. 3-4; EECo Comments, 5/4, p. 5; Fitchburg Comments, 2/23, p. 9; Wheelabrator Comments, 2/23, pp. 4-5).

c. Analysis and Findings

The Department finds that the proper regulatory response to out-of-cycle resource acquisitions is to review them on a case-by-case basis because a categorical listing of those types of projects that would be automatically approved or disapproved would be next to impossible to do so in a way that did not impair the ability of the Department and the electric companies to ensure that service to ratepayers is provided in a least-cost manner. The comments submitted on this issue convince us that the general standard for review described in D.P.U. 86-36-G is appropriate, but that its application must be considered in the context of a project's specific circumstances. The Department expects that most resources will be procured through the all-resource solicitation process, but recognizes that the legitimate and realistic time constraints faced by project developers may at times preclude them from waiting for the next solicitation cycle. We further recognize that short-term resources (less than two years in duration) may have to be procured outside of the IRM process.

In all requests for outside purchases, the electric companies will bear the burden of demonstrating that such purchases could not take place within the solicitation structure, and that the purchase is in the best interest of the ratepayers (see Section V.A.1 for a discussion of the use of incentives to ensure that electric companies procure and bring on line resources that are consistent with providing reliable electric service at least-cost to society). Further, in order to provide the development community with the type of timing information which is essential to a project's success, the Department will strive to create a schedule of electric company solicitation cycles that will be closely followed, thus allowing project developers to tailor their schedules, to the greatest extent possible, to the windows of opportunity created by the solicitation process.

4. Small Utility Participation

a. Comments on Small Utility Participation

Questions have been raised regarding whether the ratepayers of the relatively small electric companies subject to the Department's jurisdiction (namely, Fitchburg and Nantucket Electric Company ("Nantucket")) would be best served by requiring those companies to participate in the IRM solicitation process or through the use of a modified resource procurement procedure. The primary concern is whether the additional administrative cost and burden on utility personnel exceeds the benefits that would be gained through the IRM process. DOER comments that only Nantucket is a clear candidate for using an alternative process and suggests that the company be permitted to propose an alternative approach to resource acquisition (DOER Comments, 2/23, p. 23). Fitchburg recommends that the

Department adopt a flexible implementation approach, under which small companies could request and obtain waivers from specific provisions of the rules (Fitchburg Comments, 5/4, p. 1). NECA comments that small utilities, for instance those having a peak demand less than 500 MW, should be permitted to file with the Department a proposed cap on small units that may enter into a long-term standard contract without participating in the solicitation process, thus avoiding the proposed cap of 1.0 percent of the electric company's peak demand (NECA, 2/19, p. 4). WMECo comments that there should be a continuum of intensity of review, with mid-size utilities subject to more intense review than smaller utilities but to less intense review than larger utilities (WMECo Comments, 2/26, Q-Sec. III-14, p. 1)

b. Analysis and Findings

In deciding in what circumstances it would be appropriate to order a blanket exception to the IRM regulations to small electric companies, we have considered the costs and potential benefits of the IRM process. We find that Nantucket's small size means that the relative administrative costs of participating in the IRM process would be extremely high. Moreover, because of its unique geographic isolation, the potential benefits of the IRM process are limited.[16]

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16 By nature of its being unconnected to the power grid, Nantucket faces severe limitations in its ability to solicit alternative supply resources.

Accordingly, the Department finds that it would be inappropriate for Nantucket to be required to fulfill all of the requirements of these regulations. We find that the present pre-approval procedures set forth in 220 CMR 9.00, when coupled with an aggressive C&LM program and the EFSC's continuing supervision of the company's long-range forecast and supply planning process, can permit adequate opportunities for Department and EFSC review of that company's resource planning and procurement practices.[17]

Fitchburg, while a relatively small company, does not share the unique attributes of Nantucket. It is connected to the grid, it has access to affiliated service companies that can assist in the implementation of the regulatory structure, and it has successfully solicited supply resources in the past through the QF-RFP process. Accordingly, we find that Fitchburg should not receive a general exception to the regulations.[18]

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17 The Department recognizes that the EFSC currently is reviewing Nantucket's annual demand forecast and supply plan (EFSC 90-28) and, as part of that review, the EFSC will consider whether Nantucket's supply planning process meets the objectives of the IRM process.

18 Given its size, we would consider exceptions from specific requirements that may be onerous, but we would not expect to grant an exception to any major component of the process.

III. ENVIRONMENTAL EXTERNALITIES

A. Introduction

The Department defines the cost of environmental externalities as the cost of environmental damages caused by a project or activity for which compensation to affected parties does not occur, regardless of whether the costs are imposed within Massachusetts borders or elsewhere.[19] In D.P.U. 86-36-F, the Department required electric companies to include environmental externalities to the fullest extent practicable and quantifiable in their evaluations of C&LM programs and other resource options. Id., p. 22. In D.P.U. 86-36-G, the Department reaffirmed its decision to incorporate environmental externalities in the evaluation of alternative energy resources by finding that

> electric utilities' evaluation of alternate energy resource options must take into account environmental externalities to avoid the selection of resources that impose high costs not internalized in the prices bid by competing resource developers. In addition, explicitly incorporating the value of environmental externalities in resource decisions encourages resource developers to consider the value of environmental resources in

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19 We assume that the cost of mitigating environmental damages required by federal, state, and local regulations are internalized in a resource developer's production costs and, therefore, in the prices bid by developers and electric companies. Any residual damages that occur after compliance with basic environmental regulations and standards are assumed to occur without compensation to affected parties and, therefore, constitute an external cost. D.P.U. 86-36-G, p. 77.

> project proposals and enables projects that are relatively environmentally clean to compete fairly with lower-priced energy projects that have high environmental impacts.

Id. pp. 79-80.

The Department stated in D.P.U. 86-36-G that it would establish a regulatory framework that takes environmental externalities into consideration and that does so through the application of either price or non-price criteria. Id., p. 80. We stated that utilities should identify and quantify externalities as thoroughly as is reasonable for purposes of comparing resources, but we also expressed our willingness to consider alternative regulatory schemes that either, (a) put externalities in dollar terms and add them to the price of the resource (i.e., a monetization approach), or (b) select a weight for environmental externalities and a method for ranking the range of externalities in much the same way that factors other than price (e.g., reliability) are handled within the framework of the Department's existing QF regulations (i.e., a weighting and ranking approach). Id.

B. Comments and Discussion on Environmental Externalities

Many of the comments submitted in D.P.U. 89-239 are devoted to the treatment of environmental externalities in the IRM process. There is a virtual consensus among commenters that including environmental externalities in the resource evaluation process is a positive development that would allow resources with varying degrees and types of environmental impacts to be compared more accurately. In addition, most of the commenters agree that environmental externalities should be evaluated using a common framework and set of values for all utilities. Only BECo advocated giving each utility the flexibility to develop its own environmental scoring methodology (BECo Comments, 2/23, pp. 20-21).

The commenters, however, disagreed on a variety of issues involving the method of implementing an environmental component in the evaluation of energy projects. The issues raised by the commenters include:

- Using an impact-based versus a technology-based initial ranking system;
- Monetizing versus weighting and ranking externality values;
- Valuing externalities at the marginal cost of control versus cost of actual damages;
- Determining the weight of environmental externalities relative to other project selection criteria;
- Extending externality evaluations to site-specific factors;
- Extending externality evaluations to include entire fuel cycle costs;
- Extending externality evaluations to include economic and social externalities; and
- Finalizing the transitional policy for environmental externalities.

The first four issues concern the method by which environmental externality values are estimated and incorporated into the resource selection process. The next three issues concern the scope of the externality evaluation. In this section of the Order, the Department shall discuss issues with regard to the method and scope of estimating environmental externalities for use in the IRM process. The final issue, transition policy, will be dealt with more fully in the transition section of this Order. <u>See</u> Section IV.B, <u>infra</u>.

1. <u>Estimating and Incorporating Environmental Externalities into the IRM Process</u>

a. <u>An Impact-based Versus a Technology-based Scoring System</u>

In D.P.U. 86-36-G, the Department outlined three alternative methods for incorporating environmental externalities in the resource evaluation process. These methods included a technology-based, impact-based,[20] and hybrid scoring systems. See <u>Id</u>., pp. 88-93, for a full description of these methods. Most of the commenters strongly favor an impact-based or a hybrid scoring system.[21] The commenters' main objection to a technology-based system is that it scores all projects using the same fuel or turbine/boiler configuration equally, regardless of a developer's attempt at mitigating emissions from a project. Many commenters state that under a technology-based scoring system, no incentive exists for the developer to invest in cleaner technology (Mass. Audubon Comments, 2/23, pp. 2-3; CLF

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20 In this context, "impact" means emission or resource-use levels.

21 A hybrid system assigns general categories of technologies (<u>e.g</u>., coal, oil, gas, nuclear, renewable, C&LM) base environmental impact scores (as in a technology-based system), but allows each proposal to improve its base score by reducing impacts over several categories of environmental impacts (as in an impact-based system). D.P.U. 86-36-G, pp. 91-93.

Comments, 2/26, pp. 23-24; WMECo Comments, 2/26, pp. 42-44 and 5/4, pp. 21-22; Altresco Comments, 5/4, pp. 12-14).

The Department agrees that a project evaluation system that distinguishes energy project proposals by their particular expected emission levels is preferable to scoring systems that allocates fixed points based on technology types. Scoring systems based on impact levels recognize project-specific reductions of environmental impacts generally associated with energy projects of a particular turbine/boiler configuration and fuel type, and enables developers to evaluate more accurately the trade-offs between emission or resource-use levels, and the cost of controlling such emissions or reducing the level of resource use. Also, such a scoring system provides incentives for the development and procurement of cleaner technologies. Accordingly, the Department finds that electric companies should implement an environmental externality evaluation methodology that recognizes, to the greatest extent possible, the expected level of environmental impacts associated with particular project proposals. The following sections of this Order will discuss how the value of environmental impacts associated with particular energy projects should be estimated, including whether such values should be monetized, and whether these values should be based on the value of environmental damages or the cost of controlling emissions that cause damages.

b. Monetizing Environmental Externalities[22]

The commenters who support a monetization approach argue that placing dollar values on externalities makes the underlying judgments clearer and more understandable to the public. Although those that argue for a monetization scheme recognize that externality values are highly uncertain, they maintain that a weighting and ranking scheme simply obscures the monetary values implied by the scheme. In addition, these commenters oppose methods that assign a fixed weight to the externality category of the project selection criteria because such a method sets a cap on the maximum influence environmental externalities can have relative to prices bid by project developers (MassPIRG Comments, 2/26, pp. 14-15; MCSE Comments, 5/4, p. 1; DOER Comments, 3/2, pp. 12-13; CLF Comments, 2/26, pp. 33-35; Representative Alexander Comments, 5/18, pp. 6-7; The Department of Environmental Protection, Division of Air Quality Control ("DAQC") Comments, 5/25, pp. 3-5).

Several commenters support the weighting and ranking scheme proposed by MECo, with the environmental externality category accounting for 15 percent of the total project score (BECo Comments, 2/23, pp. 20-21; ComElectric Comments, 5/4, pp. 15;

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22 We note our appreciation for the considerable assistance in developing methods and estimates of environmental externalities prepared by the commenters, especially Boston Gas Company ("BGCo"), DOER, MECo, and the MIT Energy Lab.

WMECo Comments, 5/4, pp. 21-22; Wheelabrator Comments, 3/8 Letter to MECo). Altresco supports the MECo plan, but with a 30 percent weight for the environmental externality category (Altresco Comments, 5/4, pp. 12-14); EECo supports the plan with a 10 percent weight for the environmental externality category (EECo Comments, 5/4, pp. 5-6).

The MIT Energy Lab asserts that monetizing intangible environmental impacts is an unnecessary complication of an already challenging analytic task (MIT Comments, 3/13, pp. 4-5). It asserts that lower costs, lower sulfur dioxide emissions, as well as increased employment and reliability are generally preferred. Accordingly, it argues that any strategies that perform better along all of these measures independent of any weighting and ranking scheme are better (id.). Accordingly, the MIT Energy Lab recommends that the Department adopt a system-based, multi-attribute evaluation technique (id., p. 2). The multi-attribute evaluation technique recommended by the MIT Energy Lab uses "distinct measures of cost, environmental impacts, and reliability in the evaluation of resource portfolios to identify the full range of a strategies' impacts while avoiding controversy over the valuation of environmental and other externality effects" (id.).[23]

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23 The MIT Energy Lab states in its comments that resource strategies that focus exclusively on improving end-use efficiency perform poorly in reducing sulfur dioxide,

The Department finds that effective weighting and ranking approaches could be designed to account for the variation in environmental impacts among various energy resources. However, in order to design an effective weighting and ranking approach, environmental impacts and the value of those impacts would have to be estimated so that appropriate weights could be determined.[24] If weighting and ranking systems require

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nitrous oxides, and particulate emissions when compared to resource strategies that balance efficiency improvements on both the supply-side and the demand-side. According to research conducted by the MIT Energy Lab, it was found that resource strategies aimed at increasing combustion efficiency as well as end-use efficiency appear to be robust in mitigating local, regional, and global environmental impacts (MIT Comments, 3/27, p. 1). It states that these results appear to stem from the fact that over-subscribing to demand-side resources might lead to electric companies keeping older fossil-fueled generators (with high heat rates and emission levels) in service longer. Investing in new generation technology (with low heat rates and emission levels) allowed electric companies to retire old fossil-fired generation, thus reducing system-wide emission levels. The Department finds that the concerns raised by the MIT Energy Lab can be accommodated during the optimization phase of project evaluation and modification. Accordingly, the Department's final regulations require electric companies to optimize the ranking of proposals to take into account interactive effects between resources. The Department directs companies to expand the examination of interactive effects to include the interaction between new and existing resources, and to evaluate the collective environmental impacts of various committed and proposed resource combinations when preparing their draft initial resource plans and when optimizing the ranking of proposals.

24 The Department notes that, ultimately, this is true for all project selection criteria including those presently designated as "non-price" criteria.

quantification of externality values in order to determine the appropriateness of the weights, forming weights becomes unnecessary because the quantified externality values could be monetized and added directly to project costs to assist the determination of the mix of resources that minimizes cost and environmental impact simultaneously.

Accordingly, the comments in this proceeding convince the Department that externalities should be monetized to the greatest extent possible, and that such values would be added to direct resource costs (i.e., price bids of proposed resources, and the avoidable costs of existing and planned resources) for the purposes of evaluating and comparing alternative energy resources during Phase II. In categories of environmental impacts where estimates of externality values are absent, the utility must make its best effort to estimate monetary values with magnitudes appropriately weighted relative to better known values. These relative values must be estimated using the best information reasonably available.[25]

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25 All externality evaluations submitted to the Department in D.P.U. 89-239 omit environmental externalities associated with nuclear and renewable (most notably large hydro and waste-to-energy projects) energy production, and with load management programs. The Department directs each electric company to propose environmental externality values associated with nuclear and renewable energy production, and load-management projects, and to include such values in its first Phase I filing pursuant to the attached regulations.

As we stated in D.P.U. 86-36-G, the Department realizes that monetizing externality values does not constitute the elimination of subjective judgments in the evaluation of externalities. We expect that as externality values are proposed by utilities and interested parties for use in the IRM process, that the proponents of such values reveal all assumptions and judgments so that their merit can be discussed in the appropriate public forum.

c. Cost-of-Control Versus the Value of Environmental Damages

In D.P.U. 86-36-G, the Department defined environmental externalities as the costs associated with damages caused by a project for which compensation to affected parties does not occur. Assuming that the cost of pollution controls required by government law, standards and regulation is internalized into the prices offered by alternative suppliers of generation, the value of environmental externalities equals the value of damages associated with residual emissions that manage to escape into the environment despite required pollution control technologies. For example, a conventional coal-fired power plant that just meets federal New Source Performance Standards for sulfur dioxide emissions will still emit significant and specific amounts of sulfur dioxide into the atmosphere. These residual emissions cause environmental degradation and, therefore, we find that these must be taken into account in an electric company's choice of energy resources.

The purpose of estimating environmental externality values is to enable decisionmakers to compare, on a consistent basis, the social costs associated with alternative energy resources offering different prices, environmental impacts, and non-price characteristics. To illustrate the value of externalities, assume a situation where there are two generating facilities that meet federal emission limits and are alike in all respects (e.g., price, reliability) except that one facility emits significantly less pollution than the other. Most would agree that the facility with lower emissions would be preferred. If the value of environmental externalities resulting from emissions permitted by federal statute were zero, we would be completely indifferent between these two generating facilities. Since we would not be indifferent -- that is, we would prefer the less-polluting generating facility -- externalities must have an economic value that we need to consider in our resource choices.

Moving from this example, consider a comparison of two facilities that each meet government emission and resource-use requirements, but one pollutes more than the other. The value of lower environmental externalities associated with the cleaner resource would equal the maximum difference in price between two resources (where the price of the dirtier resource is lower than the price of the cleaner resource) that would be acceptable before society preferred the dirtier resource. In theory, before society opts for the dirtier resource, the difference in

DAQC Comments, 5/10, Preface; BGCo Comments, 5/18, Attachment 1, p. 4; MassPIRG Comments, 5/25, p. 3). In areas where damage costs are unknown or are uncertain, some of these commenters argue that a reasonable alternative to direct damage valuation is to use the marginal costs of control to reflect the values of environmental impacts implied by pollution standards set through other political processes (id.). These commenters argue that this approach provides conservative estimates (i.e., underestimates) of the externality costs and thus represent a proper starting point (id.).

MECo disagrees with the assumption that using the cost of control provides a conservative estimate of externality costs and asserts that cost of control methods for estimating the value of externalities should be rejected because it suffers from fundamental illogic (MECo Comments, 2/23, pp. 18-19). MECo asserts that the use of a cost of control method to estimate the value of externalities systematically tends to overstate the value of externalities (MECo Comments, 5/8, p. 2). MECo argues that society has already mandated restrictions on emissions such that the point has been achieved where the marginal cost of controlling emissions equals the marginal value of potential environmental benefits (id., pp. 4-7). Subsequently, MECo states that the marginal cost of abating any additional pollution must be greater than the marginal benefit society receives from such abatement (id.).

prices (and presumably the costs) between the dirtier and cleaner resources (i.e., the amount by which the price of the dirtier resource is lower than the cleaner resource) must be greater than the value of the incremental environmental damages associated with the dirtier resource relative to the cleaner resource. If the value of the incremental environmental damage associated with the dirtier resource is smaller than the difference in price, it would be to society's net benefit to prefer the dirtier resource. However, if the value of the incremental environmental damage associated with the dirtier resource is larger than the price difference, society would be worse off with the dirtier resource. In this case, it would be to society's net benefit to prefer the cleaner resource even though its internal price may be higher.

In order to compare different energy resources on a consistent basis, therefore, an estimate of environmental damage values associated with each resource would appear to be necessary. Given that the costs of environmental damages are difficult to estimate, methods other than direct damage cost assessments have been used to estimate externality costs.

Most of the commenters who support a monetization scheme state that using cost of actual damage values (e.g., health care costs, loss of natural resources, reduction in the quality of life) is the preferable method for valuing externalities, and argue that where these values are known, they should be used (CLF Comments, 2/26, pp. 37-39; DOER Comments, 5/2, pp. 6-8;

demand for pollution abatement using government-mandated emission limits are referred to as implied valuation methods.

As mentioned above, MECo states that implied valuation methods overstate the value of environmental externalities. MECo argues that the marginal cost of abating any additional pollution beyond that required by government regulation must be greater than the marginal benefit society receives from such abatement (MECo Comments, 5/8, pp. 4-7). Since marginal pollution control costs tend to increase and marginal pollution abatement benefits may tend to decrease with increasing levels of pollution control, MECo asserts that to control emissions significantly beyond the intersection of the marginal cost and marginal benefit curves of pollution control theoretically would diminish net societal benefits. Accordingly, MECo requests that the Department reject the implied valuation method.

However, the Department finds that MECo's argument is not relevant to the problem that the implied valuation method is attempting to address. Implied valuation methods attempt to use a proxy to estimate the value of residual pollution so that the societal cost associated with various energy resources (e.g., fossil-fuel generation, renewable-resource generation, nuclear generation, C&LM) can be compared on a consistent basis. MECo's argument implies that pollution emitted by resources meeting government-mandated emission limits cause no loss to net societal values and, therefore, need not be taken into account in the comparison between alternative energy resources.

MECo also states that cost of control methods inappropriately equate two separate and distinct concepts, the cost of controlling emissions and the value of environmental externalities (id.). In addition, MECo claims that the cost of control varies widely between utilities and that selecting one estimate as representative of all utilities constitutes an arbitrary axercise unlikely to reflect a given utility's actual cost of control (id.).

The method proposed by BGCo and DOER to estimate the value of environmental externalities equates society's willingness to pay for pollution control (and hence, society's demand to avoid costly environmental damages) with the cost of controlling pollution to comply with government-mandated emission limits. The basic rationale for using cost of pollution control as a measure of the value of pollution reduction is that the cost of pollution controls required by the government provides an estimate of the price that society is willing to pay to reduce the pollutant (BGCo Comments, 1/5, p. 8; DOER Comments (Update), 5/18, pp. 4-6).

For example, if legislators, as society's representatives, require measures that cost four dollars to reduce a pound of emission, it seems reasonable to assume that the value or worth of reducing emissions is four dollars per pound. Presumably, society is willing to pay four dollars to avoid a pound of emission in order to avoid at least four dollar's worth of external environmental damages. Methods that estimate society's

Clearly, this is not true (and MECo does not assert it is). As discussed above, if society were presented with the option to purchase either a relatively dirty or a clean resource (assuming that both resources comply with government-mandated emission limits), and these resources were alike in all other respects, society would prefer the cleaner resource to avoid costly incremental environmental damages. If we were to accept MECo's argument to its logical conclusion, we would be unable to compare the differing levels of environmental externalities caused by different energy resources that comply with government emission standards.

As a theoretical matter, MECo is correct to state that controlling emissions significantly beyond the intersection of the marginal cost and marginal benefit curves of pollution control could diminish net societal benefits.[26] The Department, however, disagrees with MECo's assumption that the decisions that have led to the setting of government standards for controlling emissions or natural resource use are based

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26 As a practical matter, the level of pollution associated with energy resources used to serve Massachusetts electricity demand represents a very small amount of global environmental externalities. Even if MECo's analysis and assumptions were entirely correct, and a large amount of pollution associated with Massachusetts electricity consumption was abated, the amount by which the incremental cost of pollution control exceeded incremental benefits would be very small when viewed from a global perspective.

solely on economic considerations of marginal costs and benefits. The level of pollution control presently mandated by legislation is based on many considerations besides an assessment of the economics of environmental damages, and, therefore, may not necessarily represent society's willingness to pay for controlling environmental damage. We acknowledge that because of the difficulties of measuring the value of environmental damages directly, it is unlikely that the level of pollution control mandated by legislation reflects society's willingness to pay to control environmental degradation. Absent better evidence, however, it is through the political process that government-mandated levels of pollution control provides a reasonable, rough proxy for of what society is willing to pay to avoid environmental externalities.

Further, we disagree with MECo that the implied valuation method overestimates the value of environmental externalities and, thus, would force power-plant developers to install pollution control equipment costing more than the benefit of abating the additional pollution. Economic theory posits that it is appropriate to value the avoidance of environmental externalities at the intersection of the marginal cost and marginal benefit curves of pollution abatement. It is at the intersection of the marginal cost and marginal benefit curves of pollution control where societal value is maximized and, thus, defines the market-clearing price or equilibrium value of externalities at the marginal cost of control would enable power-plant developers to make decisions about fuels and pollution controls in the overall context of competing with other project developers on price, environmental, and non-price variables.

The purpose of estimating the value of environmental externalities is to allow consistent comparisons between various energy resources with differing prices, environmental impacts, and non-price features. This is especially important when comparing energy conservation resources that have relatively little or no environmental externalities against generation resources that have significantly higher externalities. But it is also essential for comparing different generating facilities whose fuel and technological differences lead to significantly different pollution impacts. Estimating environmental externalities using the implied valuation method and using such values in the IRM evaluation process would give developers of generation technologies the incentive to design generation systems[29] that decrease emission levels at costs lower than the value of environmental externalities. If residual emissions allowed by government regulation were valued at zero, there would be little economic incentive for innovation of this type.

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29 That is, systems that use various combinations of fuels, fuel treatments, combustion configurations, and pollution control technologies.

avoiding environmental externalities.[27]

At quantities of pollution abatement greater than the quantity at which the marginal cost and benefit curves intersect, the amount society is willing to pay for pollution control is lower than the marginal cost of controlling that amount of pollution. In this case, societal value is enhanced by lowering the quantity of pollution control.[28]

In the IRM process, project developers installing pollution controls whose actual cost per unit of reduced emissions is greater than the per unit dollar value associated with avoiding environmental externalities would incur costs higher in comparison with any credit they would receive for having reduced emission levels. In this situation, the overall economic value of the project would be reduced and the project would receive a lower score in the IRM process. Valuing environmental

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27 The implied valuation method serves as a proxy to establish the point of intersection between the marginal cost and marginal benefit curves of pollution abatement, even though the actual control costs may not be at the intersection of such curves given our assumption that other factors besides marginal costs and benefits of pollution abatement entered into the determination of government pollution-control standards.

28 Conversely, at quantities of pollution abatement less than the quantity at which the marginal cost and benefit curves intersect, the amount that society is willing to pay for pollution control is higher than the marginal cost of controlling that amount of pollution. In this situation, societal value is enhanced by increasing the quantity of pollution control.

CO_2, and particulate emissions, both BGCo and DOER estimated similar environmental externality values. For NO_x and CH_4 emissions, however, BGCo estimated significantly higher externality values compared to DOER.[30]

With regard to BGCo's estimate of the value of externalities associated with NO_x emissions, it appears that BGCo misinterpreted NO_x emission reduction data associated with selective catalytic reduction technology (i.e., the marginal technology needed to attain a 9 ppmv emission standard) (BGCo Comments, 4/13, Exhibit 1, p. 14; DOER Comments (Update), 4/18, p. 12). The difference between BGCo's and DOER's estimate of the value of CH_4 externalities results from the method by which the impact of rapid global climate change was factored into the analysis (BGCo Comments, 4/13, Exhibit 1, pp. 11-13; DOER Comments (Update), 4/18, pp. 29-31). Although DOER is not convinced that the discounting method used by BGCo is the correct way to account for the impact of rapid global climate changes, DOER acknowledges that the rate of climate change may have comparable importance to overall climate change (DOER Comments (Update), pp. 30-31). Since DOER did not take the rate

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30 BGCo estimates the value of externalities associated with NO_x and CH_4 emissions to be about \$4.00 and \$0.84 per pound, respectively (BGCo Comments, 4/13, Exhibit 1, pp. 12-14). In comparison, DOER estimates the value of these externalities to be about \$3.25 and \$0.11 per pound, respectively (DOER Comments (Update), 4/18, pp. 12 and 29).

Without reasonable estimates of environmental damage costs, we cannot know with precision that the marginal cost of control at levels mandated by the government under- or overestimates society's demand for a cleaner environment. However, based in part on the comments in this case, it does not appear that using the results of the implied valuation method as a proxy has a significant risk of overestimating the costs of environmental externalities. Given the ongoing movement to make environmental standards more stringent rather than less stringent, and given the increasing sensitivity of the public to environmental issues, it is more likely that the marginal costs of controlling pollution are below marginal benefits at the present level of pollution control mandated by the government. As a consequence, using the cost of control as a proxy for the value of externalities is most likely a conservative estimate of society's willingness to pay for controlling externalities.

Since cost of control estimates, using the implied valuation method, is the best available proxy at this time (and clearly a better estimator of damage costs than the current assumption that the value of such damages is zero), we direct electric companies to use such control-cost estimates as a proxy for environmental damages in the absence of comprehensive damage cost estimates. In this record, both BGCo and DOER estimated the value of environmental externalities associated with various pollutants using the implied valuation method (BGCo Comments, 1/5, p. 13; DOER Comments (Update), 4/18, p. 33). For SO_x, global environmental impacts is not generally a matter subject to utility-by-utility variation. Id., pp. 86-87. Given that the Department has found that environmental externalities should be monetized to the greatest extent possible, the value of externalities relative to prices bid by resource developers would be consistent across all electric companies. The Department's finding, however, opens the question of how to set the weight of the combined price/externality category relative to the weight of the other, "non-price" ranking criteria such as reliability and system compatibility.

In order to evaluate and rank various resource proposals, monetized externality values could be directly added to the price bid by the resource proponent to determine a project's direct costs to society. If price and monetized externalities were the only criteria by which to rank projects, those projects with the lowest price, including externality cost, would be given the highest ranking. As other project selection criteria are recognized and are assigned weights to reflect their importance to the electric company, projects with positive non-price features (e.g., highly reliable projects) may be given preference over those projects with low price/externalities.[31]

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31 Although the Department views the monetization of environmental externalities as a priority over monetizing other resource attributes, the Department also sees merit in efforts to monetize other "non-price" factors. Although the Department directs electric companies to monetize

of climate change into account, its estimate of externalities associated with CH_4 emissions is probably understated. At this time, however, the Department will accept DOER's estimate of externality values associated with CH_4 emissions as a baseline value absent better evidence. In future cases, the Department expects parties to develop and propose more reasonable methods to account for the impact of rapid global climate change resulting from greenhouse gas emissions.

At this time, the Department will accept DOER's estimates of environmental externality values. Accordingly, the Department directs electric companies to use the environmental externality values proposed by DOER in this case for all electric company filings involving resource cost-effectiveness tests (including, but not limited to, preapprovals of utility C&LM and generation programs, QF RFPs, power purchase agreements, third-party C&LM contracts, IRM filings), unless it can be demonstrated in subsequent proceedings that other values for these or for other environmental externalities are more reasonable. See Table 1, _infra_. Electric companies may update such values, subject to Department review, on a case-by-case basis. Our ultimate objective, however, is to use comprehensive damage costs as the basis for environmental externalities where feasible.

d. _Application of the Price/Externality Criterion_

In D.P.U. 86-36-G, the Department stated as one of its goals that all companies use consistent categories and weights of environmental impacts because the relative value to society of more appropriate than fixing the weight of the externality component, or the price/externality component, at any particular level vis-a-vis other non-price factors for all electric companies. By fixing the weight of the externality component to achieve consistency between utilities (e.g., 20 percent of total project score), the relationship between externalities, price and non-price factors could be severely distorted leading to inappropriate resource choices. In addition, fixing the weight of the externality component to a fixed percentage of total score may systematically under- or overestimate the real value of the externality component relative to price and other non-price criteria.

Rather than directing electric companies to use environmental externality weights that are equal across all companies, the Department will seek consistency in the monetary values used by electric companies to estimate the value of environmental externalities. Accordingly, the Department's final regulations do not require the weight of the combined price/externality category as a percentage of a project's total score to be equal across all electric companies. The final regulations allow the electric companies to propose, and for the Department to review, the weights of the various categories of project selection criteria. The weight of the combined price/externality category could vary between different electric companies as the values of the non-price criteria vary relative to the price/externality category. Although a decision by the

In addition, the relationship between the combined price/externality criterion and all other criteria that have not been monetized (i.e., non-price criteria) may vary across electric companies under a weighting and ranking scheme. For example, an electric company that generates a high proportion of its electricity from oil may wish to pay a higher price for new resources that do not use oil, as compared to a company that generates its electricity from a diverse set of fuels. As a result, the weight of the price/externality component of the scoring system relative to the fuel diversity component would differ between these two companies; we believe such a difference could be appropriate.

The Department finds, therefore, that monetizing externality values, placing them on a consistent basis with price, and then allowing the relative weights of the price/externality and non-price criteria to vary in accordance with an electric companies' actual circumstances and incremental needs,[32] is

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environmental externalities to the greatest extent possible, the Department will welcome, but not now require, efforts to quantify the dollar values associated with other resource evaluation criteria (e.g., reliability, security, risks or benefits associated with fuels or fuel diversity) that presently are incorporated in the initial ranking formula using a weighting and rating scheme.

32 Of course, the Department would review and determine the appropriateness of the particular weights used in the project evaluation criteria.

In D.P.U. 86-36-G, the Department proposed that the environmental externality criteria in the IRM structure focus primarily on the impacts of a proposed facility that occur regardless of the characteristics of the site where it was proposed to be located. Id., p. 87. The Department agrees with DOER that adding local, siting-specific environmental impacts into the evaluation process would be infeasible at this point. At the time a project proponent submits a project proposal to the utility for consideration in the IRM process, it may be impossible to assess site-specific factors for all project proposals because project developers may not have acquired sites before a power sales agreement is finalized.[33] In addition, site-specific environmental impact issues associated with large generating facilities would be investigated by the EFSC with a full and fair opportunity for local communities to voice their concerns. Accordingly, the Department will not consider site-specific environmental externalities in the IRM resource evaluation process.

b. Fuel-Cycle Externalities

Some of the commenters recommend that costs associated with the entire fuel cycle (i.e., fuel extraction, fuel

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33 Additionally, for generating facilities at least 100 MW in size and proposed to be located in Massachusetts, the EFSC's statute requires consideration of, and a specific proposal for, an alternate site.

Department on externality values for use by a company in a single case will have precedential value for that and other companies on a going-forward basis, electric companies and interested parties will have the opportunity to propose such values on a case-by-case basis.

2. Determining the Scope of Environmental Externalities

a. Site-specific Externalities

The commenters were divided on the question of whether site-specific externalities (e.g., visual, noise, and wetland impacts) should be considered in the IRM process. Some argue that site-specific factors should be included, otherwise local community groups will be alienated because the issues with which they are most concerned would not be addressed (Representative Alexander Comments, 5/18, pp. 13-14; MassPIRG Comments, 2/26, pp. 10-11; MCSE Comments, 2/23, p. 5; Mass. Audubon Comments, 2/23, pp. 2-3). Others argue that site-specific factors should not be included in an externality scoring scheme. Some claim that site-specific factors will determine whether a project can be licensed and financed, and that such factors would be internalized by resource developers when developing bids (Altresco Comments, 5/4, p. 10; WMECo Comments, 2/26, pp. 40-41). DOER argues that although it would be desirable in principle to include all impacts within the resource evaluation process, it becomes increasingly difficult in practice to evaluate such impacts as the focus shifts from global to local effects (DOER Comments, 3/2, p. 4).

externalities associated with early phases of the fuel cycle. The Department finds that a priority should be placed on estimating environmental externalities that are the direct result of power-plant operation including all downstream effects (e.g., solid-waste disposal, waste-water disposal). The Department directs electric companies to consider in the project evaluation process all impacts resulting from plant operation[34] including air, water, solid waste and spent fuel disposal impacts, and resource use.

As we gain more experience and confidence with estimating externality values directly associated with power plant operation, the Department will consider proposals to expand the scope of the kinds of externalities so as to include those associated with earlier stages of the fuel cycle.[35]

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34 Such impacts should include, to the extent practicable, those environmental externalities resulting from the possibility of accidents associated with plant operation.

35 BGCo estimated the value of environmental externalities associated with oil spills at $0.20 per MMBTU (BGCo Comments, 1/5, Appendix A, pp. 85-87; 4/13, Exhibit 1, p. 16). While the Department acknowledges that environmental externalities associated with oil spills are potentially substantial depending on the nature of the spill, significant environmental externalities may exist for other major fuel types (e.g., environmental externalities associated with coal and uranium mining, and gas drilling). In order to avoid possible uneconomic fuel preferences in the resource evaluation process by including the environmental externalities associated with some fuels and omiting those of other fuels, environmental externalities associated with early stages of the fuel

transportation, facility construction, plant operation, waste disposal) should be included in the resource evaluation process (MassPIRG Comments, 2/26, p. 11; MCSE Comments, 5/4, p. 2; Mass Audubon Comments, 2/23, pp. 1-2; Representative Alexander Comments, 5/18, p. 16). Others state that it is appropriate to limit the examination of environmental externalities to externalities directly associated with plant operation (WMECo Comments, 2/26, pp. 40-41).

The Department finds that ideally, all environmental externalities associated with energy production and use should be incorporated in the resource evaluation process. It would be difficult, however, at least at the present, for the Department to estimate externalities associated with early stages of the fuel cycle (i.e., externalities incurred before plant operation). To complicate the problem, externalities associated with early stages of the fuel cycle for each fuel type have varying degrees of site-specific attributes (e.g., different mining techniques such as deep mining and strip mining, local geology, land reclamation practices and land use practices, will influence the level of externalities associated with coal and uranium mining; the cost implications of potential oil spills may vary with each shipping lane).

Given the sizable task of estimating environmental externalities associated with power-plant operation, the Department finds that it would be unnecessarily burdensome and complicated at this time to require an estimate of environmental consider environmental externalities on a global perspective, the Department finds that local job creation should not be accounted for in the resource evaluation process.

At the same time, the Department recognizes that some economic and social externalities, including a portion of economic development costs and benefits, which represent resource costs and benefits rather than transfer payments should ultimately be accounted in the resource evaluation process (e.g., resource depletion costs not incorporated in price). For now, there is insufficient information available to order their inclusion in the resource evaluation process.[37] Rather, we

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employment opportunities in other regions, net employment gains may be negligible. Id. Similarly, although there may be direct employment differences between the types of resources implemented, a global perspective requires that direct, indirect and induced jobs be included in the net employment analysis. From a global perspective, therefore, the net employment difference, including indirect and induced employment, between resources requiring differing numbers of direct employees may be smaller than it might appear.

37 We note that BGCo estimated the value of economic externalities associated with oil imports at $2.26 per MMBTU (BGCo Comments, 4/13, Exhibit 1, p. 19). This figure was estimated to reflect the vulnerability of the United States to supply disruptions and price fluctuations (id.). It is not clear to the Department whether risks associated with oil imports should be reflected in the resource evaluation process as a monetized externality, or as a component of the fuel diversity selection criteria. Rather than deciding this matter at this time, we will consider issues related to oil imports on a case-by-case basis. We encourage electric companies to address this issue explicitly in their first IRM filing.

c. Economic and Social Externalities

Some commenters argue that it is hard to create a level playing field for different resource options unless the full extent of economic and social factors are included. These costs include government subsidies (e.g., research and development, military support, tax benefits, clean-up support), economic development factors, and resource depletion. In addition, many commenters assert that special consideration should be given to projects which aid in the creation of local jobs (MassPIRG Comments, 2/26, pp. 12-14; MCSE Comments, 2/23, p. 6; Mass Audubon Comments, 2/23, pp. 1-2; Representative Alexander Comments, 5/18, p. 16).

Most of the comments received in D.P.U. 89-239 with regard to economic and social externalities request that the Department give special consideration to resources that promote local job creation as a source of external value. In Cambridge Electric Light Company and Commonwealth Electric Company, D.P.U. 89-242/246/247 (1990), the Department treated economic and social externalities (e.g., local job support) primarily as transfer payments rather than as resource costs. Id., pp. 19-20.[36] Accordingly, and consistent with our decision to

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cycle should be estimated for all major fuel types. We will consider environmental externalities associated with early stages of the fuel cycle on a case-by-case basis.

36 Constructing a power plant in Massachusetts supports local employment and reduces employment opportunities in other states and in Canada where power plants otherwise could be built to serve Massachusetts ratepayers. Since supporting local employment most likely means a reduction of

3. The comments in this proceeding convince the Department that externalities should be monetized to the greatest extent possible, and that such values would be added to direct resource costs (i.e., price bids of proposed resources, and the avoidable costs of existing and planned resources) for the purposes of evaluating and comparing alternative energy resources during Phase II. In categories of environmental impacts where estimates of externality values are absent, the utility must make its best effort to estimate monetary values with magnitudes appropriately weighted relative to better known values. These relative values must be estimated using the best information reasonably available. The Department also directs each electric company to propose environmental externality values associated with nuclear and renewable energy production, and load-management projects, and to include such values in its first Phase I filing pursuant to the attached regulations.

4. Since cost of control estimates, using the implied valuation method, is the best available proxy at this time (and clearly a better estimator of damage costs than the current assumption that the value of such damages is zero), we direct electric companies to use such control-cost estimates as a proxy for environmental damages in the absence of comprehensive damage cost estimates. At this time, the Department will accept DOER's estimates of environmental externality values. Accordingly, the Department directs electric companies to use the environmental externality values proposed by DOER in this case for all electric company filings involving resourca cost-effectiveness tests (including, but not limited to, preapprovals of utility C&LM and generation programs, QF RFPs, power purchase agreements, third-party C&LM contracts, IRM filings), unless it can be demonstrated in subsequent proceedings that other values for these or for other environmental externalities are more reasonable. See Table 1, infra. Electric companies may update such values, subject to Department review, on a case-by-case basis. Our ultimate objective, however, is to use comprehensive damage costs as the basis for environmental externalities where feasible.

5. The Department finds that monetizing externality values, placing them on a consistent basis with price, and then allowing the relative weights of the price/externality and non-price criteria to vary in accordance with an electric companies' actual circumstances and incremental needs, is more appropriate than fixing the weight of the externality component, or the price/externality component, at any particular level vis-a-vis other non-price factors for all electric companies. Accordingly, the final regulations allow the electric companies to propose, and for the Department to review, the weights of the various categories

will permit RFPs to include such externalities in the resource evaluation process if, on a case-by-case basis, the existence and level of such costs can be determined.

C. Summary of Findings and Directives on Environmental Externalities

The following summarizes the Department's findings and directives with regard to environmental externalities:

1. The Department agrees that a project evaluation system that distinguishes energy project proposals by their particular expected emission levels is preferable to scoring systems that allocates fixed points based on technology types. Scoring systems based on impact levels recognize project-specific reductions of environmental impacts generally associated with energy projects of a particular turbine/boiler configuration and fuel type, and enables developers to evaluate more accurately the trade-offs between emission or resource-use levels, and the cost of controlling such emissions or reducing the level of resource use. Also, such a scoring system provides incentives for the development and procurement of cleaner technologies. Accordingly, the Department finds that electric companies should implement an environmental externality evaluation methodology that recognizes, to the greatest extent possible, the expected level of environmental impacts associated with particular project proposals.

2. The MIT Energy Lab states in its comments that resource strategies that focus exclusively on improving end-use efficiency perform poorly in reducing sulfur dioxide, nitrous oxides, and particulate emissions when compared to resource strategies that balance efficiency improvements on both the supply-side and the demand-side. The Department finds that the concerns raised by the MIT Energy Lab can be accommodated during the optimization phase of project evaluation and modification. Accordingly, the Department's final regulations require electric companies to optimize the ranking of proposals to take into account interactive effects between resources. The Department directs companies to expand the examination of interactive effects to include the interaction between new and existing resources, and to evaluate the collective environmental impacts of various committed and proposed resource combinations when preparing their draft initial resource plans and when optimizing the ranking of proposals.

TABLE 1

SUMMARY OF ENVIRONMENTAL EXTERNALITY VALUES[38] TO BE USED BY COMPANIES IN EVALUATING THE EMISSIONS OF ENERGY RESOURCE OPTIONS

All Costs are in 1989 Constant Dollars

	Northeast United States	
	$/ton	$/lb
1. Nitrogen Oxides (NO_x)		
Ambient Air Quality	$6,500	$3.25[39]
Greenhouse	$ 0	$0.00
Total	$6,500	$3.25
2. Sulfur Oxides (SO_x)	$1,500	$0.75
3. Volatile Organic Compounds	$5,300	$2.65
4. Total Suspended Particulates	$4,000	$2.00
5. Carbon Monoxide (CO)		
Ambient Air Quality	$ 820	$0.41
Greenhouse	$ 50	$0.02
Total	870	$0.43
6. Carbon Dioxide (CO_2)	$ 22	$0.011
7. Methane (CH_4)	$ 220	$0.11
8. Nitrous Oxide (N_2O)	$3,960	$1.98

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38 DOER Estimates (DOER Comments (Update), 4/18) based on estimates prepared by Bernow and Marron, Valuation of Environmental Externalities for Energy Planning and Operations, May 1990 Update. Tellus Institute, May 18, 1990.

39 For NO_x externality estimates, the summary table on page 33 of the above-mentioned study contained a typographical error. The corrected value that appears in this Order was taken from pages 11 and 12 of the above-mentioned study.

of project selection criteria. The weight of the combined price/externality category could vary between different electric companies as the values of the non-price criteria vary relative to the price/externality category. Although a decision by the Department on externality values for use by a company in a single case will have precedential value for that and other companies on a going-forward basis, electric companies and interested parties will have the opportunity to propose such values on a case-by-case basis.

6. The Department agrees with DOER that adding local, siting-specific environmental impacts into the evaluation process would be infeasible at this point. Accordingly, the Department will not consider site-specific environmental externalities in the IRM resource evaluation process.

7. The Department finds that a priority should be placed on estimating environmental externalities that are the direct result of power-plant operation including all downstream effects (e.g., solid-waste disposal, waste-water disposal). The Department finds that a priority should be placed on estimating environmental externalities that are the direct result of power-plant operation including all downstream effects (e.g., solid-waste disposal, waste-water disposal). The Department directs electric companies to consider in the project evaluation process all impacts resulting from plant operation including air, water, solid waste and spent fuel disposal impacts, and resource use. As we gain more experience and confidence with estimating externality values directly associated with power plant operation, the Department will consider proposals to expand the scope of the kinds of externalities so as to include those associated with earlier stages of the fuel cycle.

8. Consistent with our decision to consider environmental externalities on a global perspective, the Department finds that local job creation should not be accounted for in the resource evaluation process. At the same time, the Department recognizes that some economic and social externalities, including a portion of economic development costs and benefits, which represent resource costs and benefits rather than transfer payments should ultimately be accounted in the resource evaluation process (e.g., resource depletion costs not incorporated in price). For now, there is insufficient information available to order their inclusion in the resource evaluation process. Rather, we will permit RFPs to include such externalities in the resource evaluation process if, on a case-by-case basis, the existence and level of such costs can be determined.

electric companies to include environmental externalities during the transition period when determining the evaluation criteria for QF solicitations, and when determining the cost-effectiveness of C&LM programs, power purchase agreements, and any proposed utility generation. Id., pp. 104-105. At that time, we proposed the use of a technology-based, sliding-scale adder/credit scoring method for evaluating environmental externalities during the transition period. Id., p. 106. This type of scoring method was suggested largely because of its simplicity and because it could be readily integrated into the electric companies' existing cost-effectiveness tests and bidding criteria.

As noted in Section III.B.1.a, supra, most commenters strongly favor an impact-based or a hybrid scoring system for evaluating environmental externalities, rather than a technology-based system. Mass Audubon urges the Department to adopt a transition policy for environmental externalities whereby the same scoring method and values that are to be in effect during IRM are in effect during the transition period (Mass Audubon Comments, 2/23, pp. 2-3). It comments that using a simpler, technology-based system during transition and then switching to a hybrid/impact-based system would needlessly complicate the issue and allow for a less-than-optimal resource selection process (id). EECo and WMECo suggested that each utility be allowed to develop its own approach to externalities

IV. TRANSITION POLICY

A. Introduction

Comments received in response to D.P.U. 86-36-F convinced the Department that a reasonable and clearly articulated transition policy[40] is essential to avoid any paralysis in the development and procurement of future energy resources. In D.P.U. 86-36-G, the Department proposed a transition policy that would assure electric companies and resource developers that their efforts spent in planning for, procuring, and developing resources under present regulatory standards would not be wasted or undermined when new standards are put into place. Id., p. 99. Additionally, we directed electric companies to include environmental externalities in their resource decisionmaking during the transition period. Id., p. 104. We also requested comments on whether the proposed transition policy covered a reasonable range of possibilities. Id. Many of the comments received on this issue dealt with the possiblity of expanding the existing QF solicitation process to include other third-party projects.

B. Transition Policy for Environmental Externalities

In D.P.U. 86-36-G, the Department stated that it expects

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40 For the purposes of this Order, the transition policy applies to the period between today, the date that the new regulations are issued, and the date of each company's first Phase I filing. Accordingly, the length of the transition period is different for different companies.

externalities raises the issue of including externality costs in the calculation of long-run avoided costs and RFP ceiling prices. The inclusion of these costs may improve the resource procurement process in the transition period. Accordingly, the Department will require electric companies, to the extent practicable, to modify the calculation of long-run avoided costs or RFP ceiling prices to account for environmental externalities associated with the next unit(s) used in its avoided cost calculations during the transition period.

As noted in Section III.B.1.c, supra, electric companies and interested parties will have the opportunity to propose modifications to the assigned values and to propose values fpor other environmental externalities on a case-by-case basis. During the transition period, such proposals will be accepted for the record during the Department's review of the electric companies' QF RFPs, and our review of power purchase agreements and pre-approval requests made by the companies. In cases where the Department is conducting more than one such review at the same time, we will consider consolidating comments in the various dockets so that the burden on those interested in participating in proceedings on this issue can be minimized, and any modifications to the environmental externality values can be handled consistently.

during the transition period (EECo Comments, 5/4, p. 6; WMECo Comments, 2/26, p. 48).

The Department finds that, given our findings supra, there need be no delay in the implementation of the environmental externality scoring method and values that is included in our new regulations. Accordingly, we find that the impact-based method proposed in Section III.B.1.a, and the values listed in Table 1, supra, shall be used when evaluating environmental externalities during the transition period. The Department directs electric companies whose RFPs for resources are approved by the Department during the transition period[41] to include these values for environmental externalities in the scoring criteria.[42] In addition, any demand-side or supply-side project that is submitted for pre-approval, and any power purchase agreement that is filed for our approval must include environmental externalities when determining the project's cost-effectiveness.

Further, the Department's decision to monetize environmental

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41 This includes those companies whose RFPs have been submitted to the Department, but have not yet been approved.

42 As described in Section III.B.2, the cost of environmental externalities will be added to the internal cost of the resource to calculate a new total price; as is presently the case, electric companies may propose the weight that this total price contributes relative to the total score.

participate.[44] Ideally, the Department would also expand the QF solicitation process to include C&LM projects; however, in light of the results of the collaborative effort and the Department's preapproval of electric companies' C&LM programs, as described in Section II.D.2, supra, the Department finds that the effort which would be necessary to adapt the QF solicitation process to accommodate C&LM project evaluation requirements is too complex given the expected benefits to be gained by such inclusion and the expected length of the transition period.[45]

D. Other Transition Policy Issues

Consistent with the policies adopted in today's final regulations, the Department finds that the following transition policy creates a procedural framework that ensures that resource development and acquisition can proceed unimpeded during the transition period and that will provide a smooth movement to the IRM process:

1. All resources in an electric company's portfolio that reach commercial operation or are installed during the transition period will be treated by the Department under existing standards. As discussed in Section II.A.2, supra,

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44 As discussed supra, this applies to companies whose RFPs have been submitted to the Department, but have not yet been approved.

45 Assuming that the initial IRM filing by the first company scheduled to file under IRM occurs six to nine months from the issuance of the Department's new regulations and the other electric companies' initial filings are staggered throughout the calendar year, no company should conduct more than one QF/IPP solicitation process before IRM begins.

C. QF Solicitation Process

Many commenters suggested that an appropriate transition to IRM would involve expanding the current QF solicitation process to include IPPs.[43] (EECo Comments, 5/4, p. 6) or to include both IPPs and C&LM projects (BECo Comments, 2/23, p. 22; SESCo Comments, 5/8, p. 21; Conservation Consortium Comments, 2/23, p. 6). WMECo suggests that the minimum annual solicitation requirement of 5 percent of peak load be eliminated, and that solicitations should be required only when there is a demonstrated need for capacity (WMECo Comments, 5/4, p. 23). The Conservation Consortium urged the Department to clarify its committed resource policy for those resources purchased during the transition phase (Conservation Consortium Comments, 2/23, p. 6).

The Department finds that the inclusion of IPPs in the existing RFP solicitations is consistent with the companies' obligation to provide reliable, least-cost service, and directs those electric companies whose RFPs are approved by the Department during the transition period to permit IPPs to

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43 For the purposes of this Order, an IPP is defined as a generating facility in which an electric company or companies, or an electric utility holding company or companies, holds less than 50 percent of the equity interest in the facility, and is not a QF.

V. RATEMAKING ISSUES

A. Introduction

In D.P.U. 86-36-G, the Department noted that, under the existing ratemaking framework, financial disincentives may exist for electric companies to bring cost-effective C&LM programs and both demand- and supply-side nonutility projects to fruition. Id., pp. 112-114, 117. Accordingly, the Department requested comments on how to ensure that electric companies act aggressively to pursue and procure cost-effective projects and to ensure that their commitments lead to implementation of such projects, reaping benefits to their ratepayers. In particular, the Department sought comments on whether these objectives could be achieved under the existing ratemaking framework, with somewhat increased regulatory oversight efforts, or whether the introduction of a system of financial rewards and penalties based on performance (i.e., successful implementation of cost-effective C&LM and non-utility projects) would be preferable, and if so, what form that system should take. Id., pp. 115, 118-121.

The commenters who addressed this issue support our providing some form of ratemaking incentive for utilities' implementation of both supply- and demand-side nonutility projects selected through the IRM process, or for utility C&LM programs (MassPIRG Comments, 2/26, pp. 15-16; CLF Comments, 2/26, pp. 15-16; DOER Comments, 2/23, pp. 17-18; ComElectric Comments, 5/4, pp. 18-19; MECo Comments, 2/23, p. 23; NECA circumstances may exist where a least-cost strategy compels companies in the IRM process to choose a new resource over an existing resource. In such a case, the owner of the existing resource will be made whole, either through the exercise of a buy-out provision or through the fulfillment of contract requirements.

2. Third-party resource contracts and pre-approval requests (for both supply and demand-side resources) filed with the Department during the transition period will be evaluated and treated by the Department under existing standards. These resources shall not be eligible for consideration as committed resources unless and until approved by the Department.

3. Requests for Proposal for QFs, as defined by 220 CMR 8.05, approved by the Department before the issuance of the new regulations will go forward pursuant to the existing QF regulations. Those RFPs which have been filed, but not approved, before the issuance of the new regulations will be adapted to meet the transition policy requirements described above.[46]

4. The Department recommends that companies attempt to negotiate buy-out provisions into the contracts they sign with third-parties during the transition period, regardless of whether the contract was entered into through the resource solicitation process or through negotiation.[47] The Department further orders companies to score buy-out provisions favorably in their resource solicitation evaluation procedure.

5. Parties aggrieved by the failure of an electric company to negotiate power purchase or C&LM service agreements in good faith during the transition period may petition the Department to investigate such allegations.

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46 As described supra, these requirements are the inclusion of IPPs in the solicitation process and the inclusion of the environmental externality values in the process' scoring criteria.

47 The presence of buy-out provisions in third-party contracts provides companies with added flexibility when comparing existing and proposed resources in the IRM solicitation process.

CLF Comments, 2/26. pp. 15-16; DOER Comments, 2/23, pp. 17-18; ComElectric Comments, 5/4, pp. 18-19; MECo Comments, 2/23, p. 23; MCSE Comments, 2/23, p. 10; Rep. Alexander Comments, 5/18, pp. 19-20). In addition, some commenters argue for structuring incentives on a case-by-case basis rather than delineating specific incentives in these regulations (MassPIRG Comments, 2/26, pp. 15-16; MECo Comments, 2/23, p. 23; CLF Comments, 2/26, pp. 20-21). Matters regarding the implementation of financial incentive systems are addressed below.

B. Nonutility Supply- and Demand-Side Resources

Several commenters argue for allowing utilities to receive a financial incentive when nonutility projects procured through the IRM process successfully come on-line and perform adequately. DOER specifically recommends, for example, allowing electric companies to earn an enhanced rate-of-return if they bring on-line more than 75 percent (in terms of capacity) of nonutility award group projects; no rate-of-return adjustment if they bring between 25 and 75 percent of nonutility projects on-line; and a diminished rate-of-return if less than 25 percent are brought on-line (DOER Comments, 2/23, pp. 17-18). DOER claims that the percentages can be based either on the number of projects or on the total MWs of the projects (id.).

Altresco agrees with DOER that any incentive to the electric companies should be based on a sliding-scale incentive payment and penalty system (Altresco Comments, 5/4, pp. 15-16). However, Altresco proposes that electric companies be rewarded

Comments, 2/19, p. 5; MCSE Comments, 2/23, p. 10; Rep. Alexander Comments, 5/18, pp. 19-20). None argues that the present ratemaking structure adequately addresses the identified concerns. The Attorney General cautions against amending the ratemaking framework with a system of rewards and penalties designed to promote effective operation of the IRM process, but he also concedes that some incentive system may be necessary in at least the short term (Tr. II, p. 91; Attorney General Comments, pp. 6-7).

The Department finds that the structure of its ratemaking policies under the new regulatory framework should be designed to give each utility a financial stake in accomplishing the objectives of integrated resource planning, procurement, and implementation to the maximum extent possible. Therefore, the Department finds that it would be appropriate to implement a system that rewards electric companies that are successful in implementing nonutility supply- and demand-side projects, and utility C&LM projects, that have been procured through the IRM process.

Several commenters made recommendations regarding ratemaking approaches that could be adopted to provide such financial incentives. Many parties argue that incentives should be symmetrical and based on performance; i.e., in addition to providing financial rewards to electric companies that successfully implement such projects, financial penalties should accrue to those that do not (MassPIRG Comments, 2/26, pp. 15-16;

for bringing over 50 percent of nonutility projects on-line and penalized for bringing less than 50 percent on-line (id.). NECA argues that electric companies should be rewarded not only for bringing resources on-line but also for the successful operation of those resources (NECA Comments, 2/19, p. 5).

The Department finds that any allowable incentive system must be symmetrical. While the success or failure of any particular project may not be entirely, or even largely, linked to factors directly within the control of a host utility, we find that the presence of a reward and penalty scheme will help to motivate the utilty to take steps to enhance the successful implementation of selected resources. The Department also finds that any incentive system must also be clearly linked to actual performance, and must apply to both supply- and demand-side resources. Finally, we find that the possible rewards must be relatively small in magnitude (i.e., sufficient to modify behavior, but not so large as to undermine the savings ratepayers should enjoy from the utility's selection and procurement of resources via the IRM process).

However, rather than delineate the structure and magnitude of an incentive system for nonutility resources in these regulations, the Department will address this issue on a case-by-case basis in the first and subsequent rounds of the IRM solicitations. Accordingly, the Department invites proposals from companies on this matter at the time of their first filing pursuant to the IRM regulations. It is our intention to review any such proposals that come forward in our Phase I review process. In fact, we would encourage utility proposals for incentive systems for resources acquired through resource solicitations that may occur before initiation of the IRM process.

C. Utility C&LM Programs

While all parties that commented on utility C&LM programs argue for including financial incentives for such programs, comments were divided as to the best type of financial incentive system to implement. Some favored a shared savings approach; others proposed a rate-of-return adjustment approach. However, the Attorney General thought that such incentives should only be used on a short-term basis (Attorney General Comments, pp. 6-7).

Some commenters favorably viewed allowing electric companies to recover lost revenue between rate cases that result from aggressive C&LM programs (BECo, Tr. II, p. 4; Fitchburg, 2/23, pp. 5-6), while others did not (MCSE Comments, 2/23, p. 10). The Attorney General argues that before providing companies with lost revenue from C&LM programs, the Department should open a formal proceeding to establish a decoupling mechanism (Attorney General Comments, pp. 6-7).

Since the time when the Department first requested comments on the ratemaking treatment for utility C&LM programs in D.P.U. 86-36-G, the Department has preapproved the ratemaking treatment for C&LM programs in three cases. See Western Massachusetts Electric Company, D.P.U. 89-260 (1990);

Massachusetts Electric Company, D.P.U. 89-194/195 (1990); and, Cambridge Electric Light Company and Commonwealth Electric Company, D.P.U. 89-242/246/247 (1990). In all three cases, the Department allowed electric companies to recover the direct cost of C&LM expenditures essentially as they were made. In two of those cases, the Department preapproved a financial bonus structure that is based on extraordinary performance tied to measured savings. Western Massachusetts Electric Company, D.P.U. 89-260, p. 121; Massachusetts Electric Company, D.P.U. 89-194/195, p. 178. In one case the Department approved a company's request for a revenue erosion mechanism, but required it to be performance-based and tied it to measured savings. Western Massachusetts Electric Company, D.P.U. 89-260, p. 107.

In light of these C&LM preapproval orders which have helped clarify our policies with respect to financial incentives for utility C&LM programs, we do not find it necessary to elaborate on those policies further here. Rather, we intend to continue to revisit and, if necessary, refine our policies on this issue with each subsequent C&LM preapproval review.[48]

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48 The revenue erosion mechanisms approved in D.P.U. 89-260 address, to some extent, the concerns raised by the Attorney General regarding the decoupling of utility profits from sales growth. As the IRM regulations are implemented, the Department will consider whether further actions to decouple utility profits from sales growth would be appropriate.

VI. ORDER OF INITIAL FILINGS

After the EFSC promulgates final regulations, the Department and the EFSC will issue a joint notice establishing filing dates for initial submissions by each electric company. In order to provide for an orderly and timely review of each case, such filings will be made on a staggered basis over a two-year period beginning several months after final regulations are promulgated by the EFSC.

Even though the filing dates cannot yet be established with precision, we find it appropriate to announce the order in which companies will be filing so that the companies and other interested persons will have maximum notice for planning purposes. After reviewing the comments made in this case, each company's general circumstances, and the status of ongoing cases before the Department and the EFSC, we have determined that the affected companies shall file in the following order:

1. Massachusetts Electric Company
2. Commonwealth Electric Company
   Cambridge Electric Light Company (joint filing)
3. Boston Edison Company
4. Fitchburg Gas and Electric Light Company
5. Eastern Edison Company
6. Western Massachusetts Electric Company.

VII. ORDER

Accordingly, after notice, hearing and consideration, it is hereby

ORDERED: That 220 CMR be amended to include a new Part 10.00, appended hereto, and that such new Part 10.00 be effective upon publication in the *Massachusetts Register*; and it is

FURTHER ORDERED: That the Secretary of the Department attest to a true copy of the appended Part 10.00 and transmit said attested true copy to the Office of the Secretary of State for the Commonwealth for publication in the *Massachusetts Register* for inclusion in the Code of Massachusetts Regulations and that said Part 10.00 shall be effective upon publication in the *Massachusetts Register*.

By Order of the Department,

/s/ ROBERT N. WERLIN

Robert N. Werlin, Commissioner

A true copy
Attest;

MARY L. COTTRELL
Secretary