DOER Publication

Renewable Energy & Distributed Generation Guidebook

A Developer's Guide to Regulations, Policies and Programs that Affect Renewable Energy and Distributed Generation Facilities in Massachusetts

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Disclaimer

The information in this Guidebook is general and subject to change. It is intended to serve as an introduction to regulatory issues pertaining to the development of renewable and distributed generation and should not be used as a substitute for a thorough analysis of facts and the law as they apply to any proposed project or regulatory issue. The Guidebook is not intended to provide legal advice. The Commonwealth of Massachusetts, DOER, and Environmental Futures, Inc. make no warranties, expressed or implied, and assume no legal liability or responsibility for the accuracy, completeness, or usefulness of any information provided within this Guidebook. The views and opinions expressed herein do not necessarily state or reflect those of the Commonwealth of Massachusetts, any agency thereof, or any of the organizations and individuals that have offered comments as this Guidebook was being drafted.

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In addition, users of this Guidebook are strongly encouraged to search actively for the most recent updates of governmental regulations. While the regulations cited in the Guidebook were the most recent versions, they are likely to be frequently updated.

Readers may check for recent versions of Massachusetts regulations in the *Massachusetts Register* published by the **Regulations Division**. (617) 727-2831.

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Table 1: TECHNOLOGY & PERMIT APPLICABILITY

This matrix shows the level of applicability of specific permit requirements and sections of the Guidebook to various electric generation technologies.

Legend

Level of Applicability:

- Very Likely: ●
- Possible: ◓
- Unlikely: ○

	Local		State								Federal				
	Permits and Approvals	Solar Access Laws	Energy Facilities Siting Board	Environmental Policy Act	Department of Environmental Protection	Coastal Zone Management Office	Natural Heritage Program	Department of Public Safety	Executive Office of Transportation and Construction	Historical Commission	Environmental Policy Act	Army Corps of Engineers	Discharge Permits in Water	Federal Aviation Administration	Emergency Management Administration
Section Number:	4.4	4.4.1	4.1.1	4.1.2,4.2.2	4.1.3	4.1.4	4.1.5	4.1.6	4.1.7	4.1.8	4.3.1	4.3.2	4.3.3	4.3.4	4.3.5
					Resource Protection / Waste Prevention	Coastal & Offshore Siting	Rare & Endangered Species	Liquid Fuel Tanks	Fuel Delivery Impacts	Buildings and Burial Sites	Federal Land - Site Specific	Navigable Water		Height / Proximity to Airports	Flood Hazard – Site Specific
TECHNOLOGY															
Photovoltaic	●	●	○	○	○	○	○	○	○	◓	○	○	○	○	○
Wind	●	◓	◓	◓	◓	●	●	○	○	○	◓	◓	○	●	○
Hydro	●	○	○	◓	◓	○	●	○	○	◓	◓	◓	○	○	●
Waves	●	○	○	◓	◓	●	●	○	○	○	◓	◓	○	○	●
Fuel Cells	●	○	○	○	○	○	○	◓	◓	○	○	○	○	○	○
Boiler with Steam Turbine	●	○	○	◓	●	○	○	◓	◓	○	○	○	○	○	○
Reciprocating Engine with Heat Recovery	●	○	○	◓	◓	○	○	◓	◓	○	○	○	○	○	○
Micro Turbines	●	○	○	◓	◓	○	○	◓	◓	○	○	○	○	○	○
Combined Cycle Combustion Turbines	●	○	◓	◓	◓	○	○	◓	◓	○	○	○	○	○	○

Table 2: TECHNOLOGY & INTERCONNECTION & POWER SALES

This matrix shows the applicabulity of interconnection and power sales options to various electric generation technologies.

Legend	
Level of Applicability	
Very likely	●
Possible	◒
Unlikely	○

	Interconnection (section 5.0)		Power Sales Options (section 3.0)			
TECHNOLOGY	Distribution Company	ISO New England	Net Metering	Distribution Company	Bilateral Power Purchase Agreement	Wholesale to ISO-NE Spot Market
Photovoltaic	●	○	●	●	○	○
Wind	●	◒	●	●	◒	◒
Hydro	●	◒	●	●	◒	◒
Waves	●	○	●	●	◒	◒
Fuel Cells	●	○	●	●	○	○
Boiler with Steam Turbine	◒	○	◒	◒	○	○
Reciprocating Engine with Heat Recovery	◒	○	◒	◒	○	○
Micro Turbines	◒	○	◒	◒	○	○
Combined Cycle Combustion Turbines	○	◒	○	◒	◒	◒

1.0 Introduction

Renewable Energy (RE) is used in the Guidebook to describe certain types of energy sources for an electric generation facility or technology. Renewable energy sources are naturally replenishable in a relatively short time period. They include biomass (e.g., wood), geothermal, hydropower, solar, tidal, wave, and wind.

Distributed Generation (DG) is used in the Guidebook to describe an electric generation facility or technology located in proximity to electric loads and is either connected directly to the electrical load or is interconnected to the electric grid at the distribution system level. Examples of DG facilities include rooftop photovoltaic systems, fuel cells, cogeneration or combined heat and power systems, natural gas-fired micro-turbines, and small wind turbines.

The terms RE and DG are not mutually exclusive. Many, but not all, renewable energy facilities are used in distributed generation applications. Large wind projects or biomass projects are examples of *centralized* renewable generating facilities, where the generating plant delivers power at the transmission level.

1.1 Purpose

The Massachusetts Division of Energy Resources (DOER) developed this Guidebook to provide an overview of state and federal programs, regulations, and policies that pertain to the development of renewable energy and distributed generation projects in Massachusetts. It provides information on key laws, regulations, and guidelines that renewable energy and distributed generation developers, individuals, companies, and organizations need to understand in order to obtain siting approval and permits, to interconnect with the electricity grid, and to contract to sell electricity. The Guidebook discusses other federal and state policies and programs that support renewable energy and distributed generation. The guidebook does not attempt to provide detailed assistance to developers regarding the location of potential sites, selection of generation technologies, selection of contractors, or securing financing.

The major sections of the Guidebook are as follows:

- **Section 2.0: Using the Guidebook:** a reference section that directs the reader with interest in a specific technology or application to the appropriate sections of the Guidebook.
- **Section 3.0: Selling Power from Renewable Energy and Distributed Generation:** a description of federal and state policies that facilitate the sale of electricity from renewable energy and distributed generation.
- **Section 4.0: Siting and Environmental Permitting Processes:** an overview of key local, state and federal regulations that need to be considered during the siting and permitting of renewable energy and distributed generation facilities.

- **Section 5.0: Distribution and Transmission Interconnection and Metering Issues:** a review of policies and market rules that developers need to address if they want to ensure that their generation projects are connected to the electricity grid and that their generation is metered.
- **Section 6.0: Federal and State Programs, Financial Incentives, and Policies that Support Renewable Energy and Distributed Generation:** a discussion of government and non-government incentives and programs to support the development of renewable energy and distributed generation projects.
- **Section 7.0: Case Studies:** examples that illustrate how various sizes and types of renewable energy and distributed generation projects address siting, permitting, interconnection, and the sale of power.

1.2 Target Audience

The Guidebook was written for individuals with an interest in the development and permitting of renewable energy and distributed generation in Massachusetts. The potential audience includes:

- renewable energy developers (large and small scale)
- renewable energy advocates
- investors
- equipment vendors
- building developers
- communities interested in renewable energy
- environmental, legal, economic, engineering, architectural, and energy consultants
- energy producers
- local utilities
- regional transmission operators
- competitive electricity suppliers
- federal, state, and local regulatory officials
- industrial, commercial, and residential customers considering renewable energy and distributed generation

2.0 Overview of the Guidebook

This section provides readers with guidance on how to use the information contained in this Guidebook, as well as an overview of major topics covered. Section 2.2 defines the different classes of renewable energy and distributed generation projects that are the focus of this Guidebook. Section 2.3 provides an overview of the electric industry. Sections 2.4 through 2.9 summarize important regulatory, policy, siting, and related topics for prospective developers of renewable energy projects. These topics are covered in greater detail in subsequent sections of the Guidebook. Section 2.10 provides a list of appendices.

Recognizing the range of renewable energy and distributed generation projects, and the diverse audience for the Guidebook, not every section in the Guidebook will be relevant to every reader and project.

2.1 Using the Guidebook

This Guidebook covers a wide range of Renewable Energy and Distributed Generation project types, and many local, state, and federal requirements. These requirements will have different levels of applicability to specific projects. **Table 1** and **Table 2** will help the reader determine which sections of the Guidebook are most relevant to his or her project.

A number of policies affect renewable energy and distributed generation by addressing issues related to interconnection and metering, siting and permitting, creating markets, and incentives. Most generation projects that involve the sale of electricity, including projects for renewable energy and distributed generation will need to tackle issues related to interconnection with the distribution or transmission system and to the metering of electricity output. In addition, to varying degrees most generation facilities will need to address siting and permitting issues at the state, federal, and local levels. Furthermore, federal and state regulations require local distribution utilities to purchase electricity from certain renewable energy and distributed generation projects. These policies, which help to ensure a minimum market for renewable energy and distributed generation developers, should also be understood by developers. Moreover, state and federal policies that provide additional incentives and support mechanisms to encourage the increased use of renewable energy and distributed generation are relevant to potential renewable energy and distributed generation projects.

2.2 Classification of Renewable Energy and Distributed Generation Projects

Certain federal and state regulations are designed to foster increased use of renewable energy and distributed generation. The regulations establish specific categories of renewable energy and distributed generation. These categories are essential for determining the applicability of many of the policies discussed in this Guidebook.

Federal law (see Section 4.1.3) requires utilities to purchase electricity from certain classes of renewable energy and distributed generation facilities. These facilities are called

Qualifying Facilities (QFs). QFs include both renewable energy and distributed generation, such as cogeneration, that meet certain criteria.

There are two types of QFs: **small power production facilities** and **cogeneration facilities.** The criteria for these facilities are summarized below. For a more detailed definition refer to Section 4.2.

- **Small power production (SPP) facilities:** These facilities must meet standards for size (generating capacity) and fuel use in order to meet the criteria for QFs. The capacity of a small power production facility in general may not exceed 80 MW. For small power production facilities, the primary source of energy must be biomass, waste, renewable resources (solar, wind, or hydropower), or geothermal resources. Seventy-five percent or more of a facility's total energy input must be from the above sources.

- **Cogeneration facilities:** These facilities must produce both electricity and useful thermal energy (such as heat or steam) for industrial, commercial, heating, and cooling processes through the sequential use of energy. In order to meet QF criteria, a cogeneration facility may be required to meet certain efficiency and operating standards.

Massachusetts applies the federal definition of QF at the state level for mandated distribution company purchases of electricity generated by QFs. Massachusetts also establishes another type of small generator facility, referred to as an **On-Site Generating Facility (OSGF)**, for the purpose of selling electricity back to the distribution company through net metering. An OSGF includes any generator that has a design capacity of 60 kW or less. While the definition of OSGF overlaps with the definition of QF, OSGFs also include generators 60 kW or less that do not qualify as small power production facilities or cogeneration facilities (for instance, a microturbine using natural gas that does not produce or use heat for or from another process).

Table 3 matches specific types of renewable energy and distributed generation projects with the appropriate state and federal classifications for QFs and OSGFs. These definitions apply directly to policies concerning the sale and purchase of renewable energy and distributed generation that are described in Section 4.0.

Table 3: Classification of Renewable Energy and Distributed Generation			
	QF		OSGF
Project	SPP	Cogen	
Cogeneration projects ≤ 60 kW			X
Renewable fuel	X	X	X
Fossil fuel		X	X
Non-Cogeneration Projects ≤ 60kW			X
Biomass, hydro, PV or wind system	X		X
Fuel cell (fossil fuel)			X
Fuel cell (renewable fuel)	X		X
Micro turbine (fossil fuel)			X
Micro turbine (renewable fuel)	X		X
Projects > 60 kW but ≤ 80 MW			
Biomass, hydro, PV or wind	X		no
Cogeneration (fossil fuel)		X	no
Cogeneration (renewable fuel)	X	X	no
Any Project > 80 MW	no	no	no

2.3 Electric Industry Overview

Over the past several years, the nation's electricity industry has been in a state of transition. On a state by state basis, the primary components of this historically regulated industry are being reorganized through a massive restructuring process. By enabling electricity suppliers to compete for customers, this transition is helping to create new opportunities for renewable energy. Today's restructured electric industry is made up of four primary components:

- **generation:** the production of electricity by power plants
- **transmission:** the transport of wholesale electricity over high voltage wires from power plants to distribution substations
- **distribution:** the transport of electricity over lower voltage wires from distribution substations to retail customers (such as homes and businesses)
- **customer services:** the provision of metering, billing, and information services [1]

In the regulated environment, all four of these components are provided to retail customers by their distribution company. Each state's public utilities commission, in

[1] Massachusetts Department of Telecommunications and Energy. "Summary of the Department's Electric Industry Restructuring Rulemaking Proceedings." http://www.magnet.state.ma.us/dpu/restruct/competition/index.htm.

Massachusetts, the Department of Telecommunications and Energy (DTE) regulates prices for each component. In the regulated environment, federal law requires distribution companies to purchase electricity from certain renewable generation projects. Specifics are detailed in Section 4.0.

Massachusetts has a restructured electricity market in which electricity distribution and transmission remain regulated, but electricity generation, and in some instances customer service, is competitive. This means that retail and wholesale customers may choose from competing suppliers of generation services. The retail electricity market refers to the sale of electricity to end-users such as residential and business consumers by competitive suppliers. The wholesale electricity market involves the purchase and sale of electricity among electricity suppliers, such as power marketers. Some of these companies, in turn, sell electricity to end-users. In restructured markets, renewable energy facilities are able to sell power to distribution companies and to other market participants, including competitive suppliers.

2.4 Selling Power from Renewable Energy and Distributed Generation

The Public Utility Regulatory Policies Act of 1978 (PURPA) is a federal law that facilitates the development of markets for renewable electricity generation. Under PURPA, local utilities are required to purchase electricity from certain Qualifying Facilities (QFs), including renewable and distributed generation, at the distribution company's avoided cost. Avoided cost, which broadly means the price that the distribution company would otherwise have to pay for electricity, is determined by each state's regulatory body, in Massachusetts, the DTE. The Federal Energy Regulatory Commission (FERC) is responsible for implementing PURPA's "must buy" provision, and for certifying QFs. For more information on PURPA and QFs refer to Section 4.0.

In Massachusetts, the DTE recently modified its QF regulations to redefine a distribution company's avoided cost for federally mandated purchases from QFs. As a result of this modification, avoided cost is now based on the wholesale market price of electricity.

The opening of the wholesale market allows renewable and distributed generators to sell power to competitive suppliers as well as to distribution companies. In some cases, renewable energy and distributed generation facilities also have the option of selling their power to a power exchange that is administered by the Independent System Operator (ISO) New England. For more information on the DTE's QF regulations refer to Section 4.3.2.

At the federal level, a number of electric industry restructuring bills are under consideration. Most of these bills would eliminate PURPA-mandated purchases of qualifying generation by distribution companies. The outcome of electric industry restructuring at the federal level may significantly alter existing federal and state regulations concerning the licensing and contracting of renewable and distributed generation for electricity sales. Users of this Guidebook are strongly encouraged to search actively for the most recent updates of governmental regulations..

2.5 Siting and Environmental Permitting

Renewable and distributed generation developers must comply with federal, state, and local regulations pertaining to siting and environmental permitting. Compliance with the Massachusetts Environmental Policy Act (MEPA), which examines a project's potential environmental impact, is one initial step in the state's review of a proposed facility. The developer will need to examine the MEPA thresholds to determine whether aspects of the potential project exceed specified thresholds and therefore require further analysis and permits. Another key step may involve acquiring various permits from the Massachusetts Department of Environmental Protection (DEP). The Massachusetts Office of Coastal Zone Management must review any project proposed in its jurisdiction for consistency with its program policies before any federal action can take place. In addition, developers will need to consider federal and local permitting issues. For more information on siting and environmental permitting refer to Section 4.0.

2.6 Grid Interconnection and Metering

In order to sell power, renewable and distributed generation developers in Massachusetts must be interconnected with New England's electricity grid. Depending upon the size of the project, they must either interconnect with the distribution company or with the New England Power Pool (NEPOOL) transmission system, which is administered by an entity known as the ISO-New England. Small facilities will generally interconnect with the distribution company, while large QFs will likely interconnect with the transmission system directly. The type of interconnection will depend largely on the location of the facility. Large projects are most likely to be sited where they can interconnect directly to the transmission grid, whereas small projects are likely to be sited near the distribution system.

Renewable and distributed generation developers will also have metering that reflects how they sell their power. Some facilities will be eligible for net metering, which allows an OSGF to receive credit for surplus generation against the retail cost of electricity. Other large facilities may require metering in order to participate directly in the ISO market. For more information on grid interconnection and metering refer to Section 5.0.

2.7 Federal and State Programs and Policies that Support Renewable and Distributed Generation

A number of federal and state programs and policies support the development of renewable and distributed generation. Federal agencies offer tax credits, rebates, grants, and financing resources for renewable and distributed generation projects. In addition, Massachusetts has the following programs and policies that help to support renewable energy and distributed generation:

- Renewable Portfolio Standard
- Renewable Energy Trust Fund
- an electricity information disclosure policy that requires electricity suppliers to provide information to consumers on the sources of their electricity supply
- tax credits.

For more information on incentives and policies to support renewable and distributed generation refer to Section 6.0.

2.8 Overview of Regulatory Requirements by Project Class

The Guidebook covers a wide range of renewable energy and distributed generation technologies and projects. The Guidebook includes information that may not pertain to every reader or project. This section identifies the parts of the Guidebook that are particularly relevant to specific project types (also see Table 2).

2.8.1 Small QFs and OSGFs (<60 kW)

Small Renewable QF and OSGFs have generating capacities of 60 kW or less. Relevant projects could include rooftop photovolatic systems, small wind projects, small cogeneration, and microturbines. For a relevant case study, refer to Section 7.1, which discusses the development of a photovoltaic project. Developers of small renewable QF and OSGFs will need to focus on the following issues:

- **Section 3.0: Selling Power from Renewable Energy and Distributed Generation:** A renewable QF that is 60 kW or less or an OSGF can qualify for net metering in Massachusetts. For more information refer to Section 4.3.2.2.

- **Section 4.0: Siting and Environmental Permitting Processes:** Most developers will need to focus on local siting and zoning issues. Developers of some small projects, such as wind projects or those that involve the combustion of fossil fuels or biomass, may also need to address some state environmental review processes or permits that pertain to emissions, noise impacts, land use, etc. For more information refer to Sections 4.1.3 and 4.4.

- **Section 5.0: Distribution and Transmission Interconnection and Metering Issues** Developers of small renewable energy projects will need to understand procedures for interconnecting with the local distribution company. For more information refer to Section 5.1.

- **Section 6.0: Federal and State Programs, Financial Incentives and Policies that Support Renewable Energy and Distributed Generation:** Small renewable energy developers can benefit from a number of incentives and policies. Developers of such projects should review Section 6.0 to explore opportunities that might enable them to receive additional support.

2.8.2 Larger QF Renewable Energy Projects (> 60 kW but less than 80 MW)

Larger QF renewable energy projects include renewable energy projects greater than 60 kW. Relevant projects could include wind projects, biomass energy projects (including landfill gas), small hydro projects, and even larger solar power projects. For a relevant case study refer to Section 7.4, which discusses the development of a wind project, and Sections 7.2 and 7.3, which discuss the development of landfill gas projects. In general, developers of larger renewable QF projects will need to focus on the following issues:

- **Section 3.0: Selling Power from Renewable Energy and Distributed Generation:** Developers of larger QF renewable energy projects will need to go through the federal QF certification process and certain Massachusetts administrative procedures for selling power to utilities. For more information refer to Sections 3.2 and 3.3.

- **Section 4.0: Siting and Environmental Permitting Processes:** Most larger renewable energy projects will not be subject to state Energy Facility Siting Board regulations if they are less than 100 MW. Many projects may need MEPA review or may need to meet DEP permit requirements. For example, biomass to energy projects and wind energy projects may need to consult the DEP Air Program Planning Unit concerning emissions and noise control. Biomass to energy projects may also need to consult the DEP Waste Programs Planning Unit concerning the handling and disposal of solid waste materials. Larger projects will likely need to address other DEP permit issues. Most developers will also need to address local siting and zoning issues. For more information refer to Section 4.0.

- **Section 5.0: Distribution and Transmission Interconnection and Metering Issues:** Depending on project size and location, developers of larger QF renewable energy projects may need to understand how to interconnect and meter with the local distribution company and/or possibly with the ISO. For more information refer to Sections 4.1 and 4.2.

- **Section 6.0: Federal and State Programs, Financial Incentives, and Policies That Support Renewable Energy and Distributed Generation:** The developers of larger QF renewable energy projects can benefit from a number of incentives and policies. Developers of such projects should review Section 5.0 to explore opportunities to receive additional benefits.

2.8.3 Cogeneration Projects

Some types of QF projects qualify as cogeneration. For a relevant case study refer to Section 6.5, which discusses the development of a natural gas cogeneration project. In general, developers of cogeneration projects will need to focus on the following issues:

- **Section 3.0: Selling Power from Renewable Energy and Distributed Generation:** Developers of QF cogeneration projects will need to go through the federal QF certification process and Massachusetts administrative procedures for selling power to utilities. For more information refer to Sections 3.2 and 3.3.2.

- **Section 4.0: Siting and Environmental Permitting Processes:** Most QF cogeneration projects will not be subject to state Energy Facility Siting Board regulations if they are less than 100 MW. Some projects may require MEPA review and be subject to certain DEP permit requirements and to CZM federal consistency review. For example, the developers of some cogeneration projects may need to consult the DEP Air Program Planning Unit concerning air quality and noise permits, while the developers of cogeneration facilities using biomass may need to consult the DEP Waste Programs Planning Unit with regard to permits for solid waste. In general, developers of larger cogeneration projects will also need to address other DEP and state jurisdictional issues involving water use and discharge, fuel storage, and other matters. Applicability of CZM program policies is generally site-specific. Most developers will also need to address local permitting issues. For more information refer to Section 4.0.

- **Section 5.0: Distribution and Transmission Interconnection and Metering Issues:** Depending on project location, a developer of a QF cogeneration project needs to understand how to interconnect and meter with the local distribution company and/or possibly the ISO. For more information refer to Sections 4.1 and 4.2.

- **Section 6.0: Federal and State Programs, Financial Incentives, and Policies That Support Renewable Energy and Distributed Generation:** In general, the developers of QF cogeneration projects will not directly benefit from the policies and programs discussed in Section 5.0, unless they rely upon renewable fuels as a generation source.

2.9 Non-QF and Non-OSGF Distributed Generation Projects

This category includes distributed generation projects that do not qualify as QFs and do not qualify as OSGFs and net metering because their capacity exceeds 60 kW. Relevant projects could include microturbines or fuel cells that use fossil fuels solely for the purpose of generating electricity. In general, developers of these projects will need to focus on the following issues:

- **Section 3.0: Selling Power from Renewable Energy and Distributed Generation:** Distributed generation projects that do not meet the requirements for QFs or OSGFs will not be eligible for mandatory distribution company purchases of their electricity output. If developers are unclear about project eligibility, they should refer to Sections 3.2 and 3.3.2.2.

- **Section 4.0: Siting and Environmental Permitting Processes:** Most non-QF and non-OSGF distributed generation projects will not be subject to state Energy Facility Siting Board regulations if they are less than 100 MW. Many projects may require MEPA review and may need to meet certain DEP permit requirements. For example, developers of some projects may need to consult the DEP Air Program Planning Unit about air quality and noise permits. Most developers will also need to address local permitting issues. For more information refer to Section 4.0.

- **Section 5.0: Distribution and Transmission Interconnection and Metering Issues:** Depending on the location of the project, developers of non-QF and non-OSGF distributed generation projects need to understand how to interconnect and meter with the local distribution company and/or potentially be linked with the ISO. For more information refer to Sections 5.1 and 5.2.

- **Section 6.0: Federal and State Programs, Financial Incentives, and Policies That Support Renewable Energy and Distributed Generation:** In general, developers of non-QF and non-OSGF distributed generation projects will not directly benefit from the policies and programs discussed in Section 6.0 unless they rely upon renewable fuels as a generation source.

2.10 Appendices

For easy reference, the following Appendices are contained in the Guidebook:

- **Appendix One: Glossary** - A glossary of key terms
- **Appendix Two: Acronyms** - A list of acronyms and their definitions
- **Appendix Three: Contact List** - A list of key federal and state agency contacts
- **Appendix Four: Types of Permits/ Procedures -** A checklist of key permits and issues that renewable energy and distributed generation developers may need to consider. The checklist is sorted by: 1) sale of electricity, 2) siting and permitting, and 3) interconnection
- **Appendix Five: Relevant Policies** - A detailed bibliography of laws and regulations that pertain to the development of renewable energy and distributed generation
- **Appendix Six: Resources** - A bibliography of additional resources, such as guidebooks, manuals, and web pages, that provide additional guidance to renewable energy and distributed generation developers
- **Appendix Seven: Sample Projects** - A list and brief description of renewable energy projects in Massachusetts

3.0 Selling Power from Renewable Energy and Distributed Generation

Renewable generation developers should understand the policy initiatives that shape the market for renewable energy. The following provides:

- a summary of the development of policies that now regulate the sale of power from renewable and distributed generation
- a discussion of how a facility becomes a Qualifying Facility (QF), as well as the proposed regulations that govern distribution company purchases from QFs
- a summary of the functions of the Independent System Operator (ISO) that pertain to the wholesale market for electricity in Massachusetts

3.1 Federal Laws and Regulations

The Public Utility Holding Company Act (PUHCA) and the Federal Power Act (FPA) of 1935 establish the framework for the traditional regulated electric industry. The FPA gives the Federal Energy Regulatory Commission (FERC) regulatory authority over wholesale electricity markets. The Public Utilities Regulatory Policy Act of 1978 (PURPA) requires utilities to purchase electricity from certain renewable and distributed generation facilities.

More recent policy initiatives, such as the Energy Policy Act of 1992 (EPAct) and subsequent FERC orders, encourage wholesale and retail competition for electricity generation. These measures have prompted some states, including Massachusetts, to allow for retail competition, and have led to the creation of competitive markets for all generators, including those producing renewable energy and distributed generation.

Federal electricity restructuring initiatives now under discussion may lead to the repeal of PURPA and may alter other regulations that require the purchase of power from renewable and distributed generation. Users of this Guidebook are strongly encouraged to search actively for the most recent updates of governmental regulations.

3.1.1 Public Utility Holding Company Act (PUHCA) and the Federal Power Act (FPA) of 1935

PUHCA, 15 USC 79 et seq., and the FPA, 16 USC 792 et seq., were enacted to stop unfair market practices by electric and gas utilities acting as monopolies.

PUHCA allows for the regulation and dismantling of large utility systems that developed in the early days of electric power generation. It significantly restricts owners of electric utilities and power generating facilities from operating in more than one region by requiring strict regulation of interstate electric utility holding companies. Utilities are granted exclusive franchise territories and are required to provide electricity to all customers within those territories at regulated rates.

The FPA grants FERC jurisdiction over wholesale sales of electricity. The regulation of retail sales is generally left to state public utility commissions, such as the Massachusetts Department of Telecommunications and Energy.

3.1.2 Federal Energy Regulatory Commission (FERC)

FERC is an independent regulatory agency within the U.S. Department of Energy (DOE) that regulates the transmission and wholesale sales of electricity in interstate commerce, among other responsibilities. Its governing body is a five-member commission, the members of which are appointed by the President with the advice and consent of the U.S. Senate.

FERC approves rates for wholesale electric sales of electricity and transmission in interstate commerce involving private utilities, power marketers, power pools, power exchanges and independent system operators. FERC acts under the legal authority of the FPA, PURPA, and EPAct. FERC is responsible for certifying qualifying small power production and cogeneration facilities for PURPA mandated distribution company electricity purchases.[2]

In the past, FERC has used its authority to regulate the price of wholesale electricity sales. FERC has traditionally implemented this authority as rate-of-return price regulation that allows the seller to recover its costs plus a regulated rate-of-return on equity invested. Recently, FERC has opened up the wholesale electricity market to increased competition. In restructured markets, FERC is still responsible for regulating the wholesale transmission market and ensuring that market participants have non-discriminatory open access to the transmission system.

3.1.3 Public Utility Regulatory Policies Act of 1978 (PURPA)

PURPA encourages the development of non-utility cogeneration and small-scale renewable electric power plants. These generators are classified as QFs. PURPA defines two kinds of QFs: 1) small power producers with a rated capacity of 80 megawatts or less that receive at least 75 percent of energy input from renewable resources; and 2) cogenerators that meet certain criteria (see section 3.2 for detailed criteria). Utilities may not own more than 50 percent of a QF. FERC implements PURPA through regulations outlined in 18 CFR 292. In addition, FERC is responsible for oversight of the QF certification process.

PURPA provides several benefits to QFs, including the following:

- **Interconnection:** Requires distribution companies to provide grid interconnection to all QFs within its service territory.

- **Purchases:** Requires distribution companies to purchase electricity from QFs at a price equal to the distribution company's avoided cost. The avoided cost is what it

[2] http://www.ferc.fed.us/electric/electrc2.htm.

would have otherwise cost the Distribution Company to generate or purchase electricity. The avoided cost has traditionally been determined by the utility regulatory agency in each state. This requirement does not preclude QFs from entering into long-term negotiated power contracts with utilities. PURPA allows a QF and a distribution company to contract at a price lower than avoided cost. Many facilities choose to enter into long-term contracts at a predetermined fixed or escalating price less than projected avoided costs in order to avoid the risk of fluctuations in actual avoided costs.

- **Sales:** Requires distribution companies to sell electricity, including supplementary, back-up, and maintenance power, to QFs within the distribution company's service territory.

In addition, PURPA exempts QFs from certain regulations. For example, QFs are exempt from being defined as an "electric utility company" within the meaning of PUHCA. This means that most QFs are not subject to the ownership limitation that PUHCA places on electric utilities.

3.1.4 Energy Policy Act of 1992 (EPAct)

EPAct, Pub.L. 102-486, allows a new type of electricity producer called the Exempt Wholesale Generator (EWG). EWGs are permitted to generate and sell electricity at wholesale prices without being regulated as a utility under PUHCA. This limits PUHCA's restrictions on the development of non-utility generation. In addition, EPAct requires FERC to provide non-discriminatory access to the wholesale transmission system. While EPAct does not directly allow for EWGs to sell energy to retail customers, it helps to open competitive markets for generation by deregulating the wholesale market and allowing EWG's to sell power not only to utilities but also to competitive suppliers (competitive suppliers are companies that sell electricity to retail customers).

3.1.5 FERC Orders 888 and 889

In April 1996, using authority granted by EPAct, FERC issued Orders 888 and 889. These orders encourage competition by requiring electric utilities to provide non-utility power producers, including QFs, equal and non-discriminatory access to electric transmission facilities. In issuing these orders, FERC sought to eliminate transmission monopolies by requiring all utilities that own, control, or operate transmission facilities to do the following:

- file open-access, non-discriminatory transmission tariffs with FERC
- provide transmission service (including ancillary services) under open access tariffs to market participants
- develop and maintain same-time information systems to provide existing and potential users the same access to transmission information as the public utility
- separate the transmission function from the generating and marketing functions

FERC proposes the use of "independent system operators" (entities not affiliated with any market participants and without financial interest in the operation of the transmission system and the market for wholesale electricity) or similar entities to provide open access to the grid. FERC's open access policies require prices for transmission services to be separated from prices for generation services.

3.1.6 Federal Restructuring Outlook

The emerging wholesale electricity market prompted many state regulators and state legislatures, including those in Massachusetts, to enact comprehensive regulatory orders and/or restructuring legislation.

In addition, FERC's open access rules have created a competitive market for the use of transmission lines. The different transmission tariffs and rules developed by regional transmission organizations may impact renewable and distributed generation.

In Congress, a number of comprehensive federal restructuring bills have been introduced. Most of those bills address three primary issues:

- eliminating PUHCA restrictions on the ability of electric utilities to diversify their assets and operations
- eliminating PURPA mandated purchases of non-utility power, including QF power, by electric utilities
- permitting retail electric customers to choose their generation from any available source (retail wheeling)[3]

In place of PURPA mandated purchases of renewable energy, some federal bills propose a renewable portfolio standard that would require electricity suppliers to include a certain percentage of renewable energy in their generation portfolio. Some federal bills also contain language that would support universal net metering, enabling small power producers to sell excess generation to utilities. The outcome of the federal restructuring debate -- which is not settled as of the date of the Guidebook's publication -- could substantially alter the procedures under which electric utilities are required to purchase electricity from QFs under PURPA.

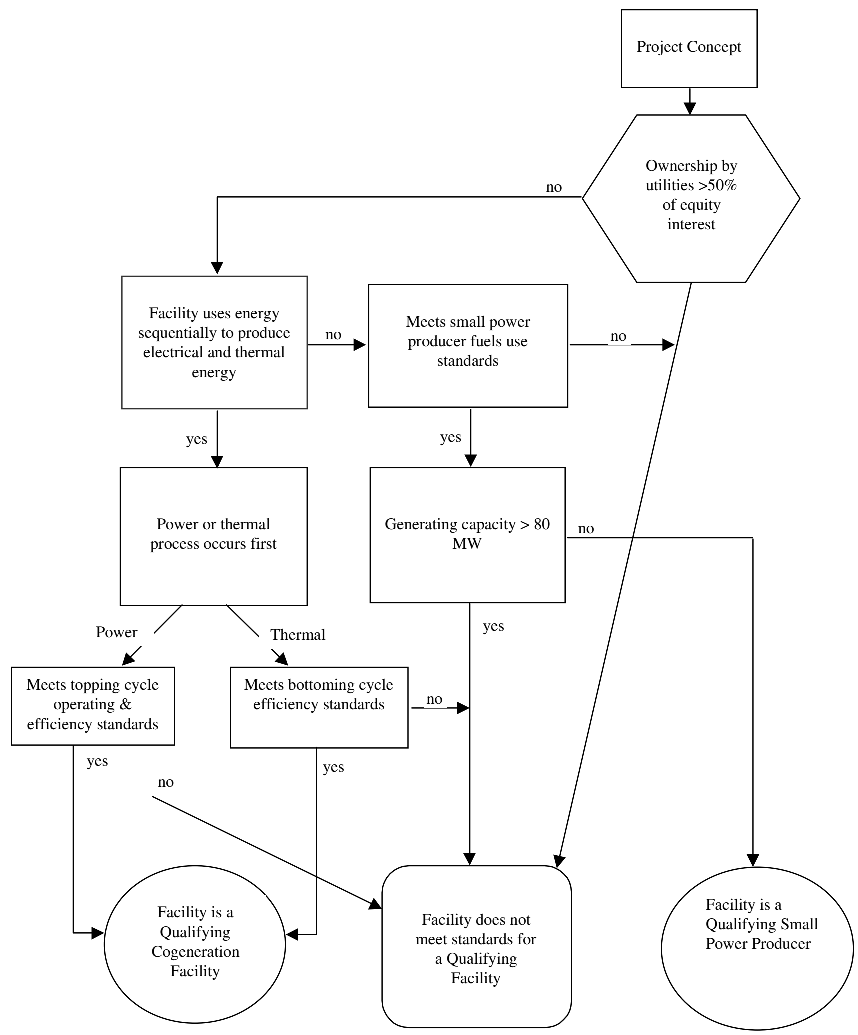
[3] Parker, Larry. RL30087: Electricity Restructuring: Comparison of H.R. 667, S. 516, H.R. 1587, and the Administration's Proposal. Congressional Research Service Issue Brief for Congress. June 16, 1999.

3.2 Becoming a Qualifying Facility (QF)

This section reviews the requirements and procedures for renewable and distributed generation projects to qualify as QFs, thereby becoming eligible for mandatory electricity purchases by their local distribution company under PURPA.

There are two types of QFs: small power production facilities and cogeneration facilities. The figure below presents a flow chart depicting the determination process for a QF.

Figure 1: Identifying a Qualifying Facility



3.2.1 Ownership Requirements

A cogeneration facility or small power production facility cannot qualify as a QF if more than 50 percent of the equity interest in the facility is held by an electric utility or utilities, by an electric utility holding company, or by any combination of the above. If a wholly or partially-owned subsidiary of a distribution company or holding company has ownership interest in a facility, it will be considered to be ownership by the distribution company or holding company. (In certain cases, utilities, utility holding companies, and subsidiaries may hold more than 50 percent of the debt interest in the facility. In addition, certain subsidiaries of utility holding companies may be found by FERC or by the Securities and Exchange Commission to be exempt from this rule pursuant to 15 USC 79. On a case by case basis, FERC may grant certification to facilities owned by partnerships in which utility affiliates have provided more than 50 percent of the capitalization in return for partnership interests that resemble preferred stock.)

3.2.2 Criteria for Small Power Production Facilities

Small power production facilities must meet standards for size (capacity) and for fuel use to meet the criteria for qualifying facilities.

- **Size:** The capacity of a small power production facility may not exceed 80 MW.[4] The 80 MW cap also applies to small power production facilities that share the same energy source, are owned by the same entities or their affiliates, and are located at the same site. Subject to additional FERC determination, small power production facilities are considered to be located at the same site if they are within one mile of each other, and, in the case of hydropower facilities, if they use water from the same impoundment (for example a water storage area or pond, for power generation).

- **Fuel Use:** For small power production facilities, the primary source of energy must be biomass (meaning any organic material not derived from fossil fuels, such as woody material, waste, etc.),[5] renewable resources, or geothermal resources, as

[4] There is no size limitation for a grandfathered eligible solar, wind or waste facility as defined by Section 3 (17) E of the Federal Power Act. "Eligible solar, wind, waste or geothermal facility" means a facility that produces electric energy solely by the use, as a primary energy source, of solar energy, wind energy, waste resources or geothermal resources; but only if either of the following is submitted to the Commission not later than December 31, 1994: 1) an application for certification of the facility as a qualifying small power production facility; or 2) notice that the facility meets the requirements for qualification; and if the construction of such facility commences not later than December 31, 1999, or, if not, reasonable diligence is exercised toward the completion of such facility taking into account all factors relevant to construction of the facility.

[5] The definition of waste includes, but is not limited to, the following materials that the Commission previously has approved as waste: 1) Anthracite culm produced prior to July 23, 1985; 2) Anthracite refuse that has an average heat content of 6,000 Btu or less per pound and has an average ash content of 45 percent or more; 3) Bituminous coal refuse that has an average heat content of 9,500 Btu per pound or less and has an average ash content of 25 percent or more; 4) Top or bottom subbituminous coal produced on Federal lands or on Indian lands that has been determined to be waste by the United States Department of the Interior's Bureau of Land Management (BLM) or that is located on non-Federal or non-Indian lands outside of BLM's jurisdiction, provided that the applicant shows that the latter coal is an extension of that determined by BLM to be waste; 5)

defined by PURPA and related regulations. In general, waste means an energy input that has little or no commercial value and exists in the absence of the qualifying facility. Waste includes certain types of municipal solid waste and landfill gas. Renewable resources include solar, wind, and hydro.

Seventy-five percent or more of each facility's total energy input must be from the above sources. A primary energy source constituting 50 percent or more biomass is considered to be biomass. Small power production facilities are permitted to use oil, gas, or coal as supplementary fuels, but the use of these fuels for supplementary uses may not exceed 25 percent of total energy input during a twelve-month period.

3.2.3 Criteria for Cogeneration Facilities

As defined by FERC, 18 CFR 292, cogeneration facilities are those that produce electricity as well as useful thermal energy (such as heat or steam) for industrial, commercial, heating, and cooling processes through the sequential use of energy. In order to meet QF criteria, a cogeneration facility must meet efficiency and operating standards if it is a topping-cycle facility, and an efficiency standard if it is a bottoming-cycle facility.

- **Bottoming-cycle facility:** the energy input to this kind of system is first applied to a useful thermal energy application or process, and at least some of the reject heat emerging from the process is then used for electric power production. In a bottoming-cycle system, high-temperature thermal energy is produced first for applications such as reheat furnaces, glass kilns, or aluminum metal furnaces. Heat is extracted from the hot exhaust stream and transferred (through one or more mediums) to drive a turbine. Bottoming-cycle systems are generally used by industrial processes that require very high temperature heat, thus making it economical to recover the waste heat.[6]

- **Topping-cycle facility:** the energy input into this type of facility is first used to produce useful electric power output, and at least some of the reject heat from the power production process is then used to provide useful thermal energy. In a typical topping-cycle system, the energy input to the system is first transformed into electricity by using high-temperature, high-pressure steam from a boiler to drive a turbine to generate electricity. The waste heat, or the lower pressure steam exhausting from the turbine, is used as a source of process heat. Topping-cycle

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Coal refuse produced on Federal lands or on Indian lands that has been determined to be waste by the BLM or that is located on non-Federal or non-Indian lands outside of BLM's jurisdiction, provided that applicant shows that the latter is an extension of that determined by BLM to be waste; 6) Lignite produced in association with the production of montan wax and lignite that becomes exposed as a result of such a mining operation; 7) Gaseous fuels, except: i) Synthetic gas from coal; and ii) Natural gas from gas and oil wells unless the natural gas meets the requirements of 2.400 of this chapter; 8) Petroleum coke; 9) Materials that a government agency has certified for disposal by combustion; 10) Residual heat; 11) Heat from exothermic reactions; 12) Used rubber tires; 13) Plastic materials; and 14) Refinery off-gas (18 CFR 220.202).

[6] Energy Information Administration. "Electric Power Annual 1994 Volume 2 (Operational and Financial Data). Washington, D.C. 1994.

systems are more common than bottoming-cycle facilities and are used in commercial, rural, and industrial applications.[7]

- **Efficiency Standards:** Bottoming-cycle facilities that use natural gas for supplementary firing, and topping-cycle facilities that use natural gas or oil as a fuel, must meet efficiency standards to qualify as QFs. Topping-cycle facilities will also need to meet certain operational standards. FERC may waive efficiency standards if a facility can demonstrate significant energy savings.

  - **Bottoming-cycle facilities:** The useful annual power output of a bottoming-cycle facility must be equal to or greater than 45 percent of the energy input of natural gas and oil for supplementary firing.[8] For instance, if 50 Btus of natural gas are directly used to generate electricity, than a qualifying bottoming-cycle facility must produce at least 22.5 Btus of electricity (45 percent of 50 Btus).

  - **Topping-cycle facilities:** The useful annual power output of a topping-cycle facility plus one-half the useful thermal energy output must be no less than 42.5 percent of the total energy input of natural gas and oil to the facility. For example if a qualifying topping-cycle facility uses 50 Btus of natural gas, the total electrical output and 50 percent of the useful thermal energy output must be equal to or greater than 21.5 Btus (42.5 percent of 50 Btus). However, if the useful thermal energy output of the facility is less than 15 percent of the total energy output of the facility, the standard is 45 percent of the total energy input of natural gas and oil to the facility rather than 42.5 percent.

- **Operating Standards for Topping-Cycle Facilities:** During the twelve-month period beginning with the date the facility first produces electricity (and each subsequent calendar year) at least 5 percent of the total energy output of the facility must be useful thermal output. In the event of overlap, the facility will need to comply with both periods. If the thermal use is not a common commercial or industrial use, or the buyer of thermal output is an affiliate of the QF, FERC may scrutinize the sales arrangements to determine whether the facility's thermal output is truly commercially useful.

3.2.4 Procedures for Obtaining Qualifying Status

There are two different ways for a renewable and distributed generation developer to obtain QF status for a proposed facility: 1) self-certification; and 2) FERC certification.[9] To streamline the certification process, FERC created the Form No. 556 filing requirement that outlines information requirements.[10]

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[7] Energy Information Administration. "Electric Power Annual 1994 Volume 2 (Operational and Financial Data). Washington, D.C. 1994.

[8] Supplementary firing means energy used only in the thermal process of a topping-cycle facility, or only in the electric generating process of a bottoming-cycle facility (18 CFR 292).

[9] 18 CFR 292.206.

[10] Form No. 556 is codified in FERC's regulations at 18 CFR 131.80.

Applicants may choose to certify a facility through a notice of self-certification (no fee) or by applying for FERC certification (fee). Self-certification may be a simpler and quicker process, but it does not provide the applicant with the same degree of certainty as FERC certification. Project financiers or distribution companies may require facilities to seek FERC certification to mitigate any uncertainty. This is especially true when a facility does not clearly meet the technical and ownership requirements for qualifying status. New applicants may consider filing a notice of self-certification first and then filing an application for FERC certification if the need arises.

Developers should also know that a distribution company is not required to purchase electricity from a QF with a capacity of 500 kW or more until 90 days after the facility has notified the utility that it is a QF or 90 days after the facility has applied for FERC certification.

The following sections provide an overview of the certification process. For more information, FERC administers a web site entitled "How to Obtain Qualifying Status for Your Facility" at http://www.ferc.fed.us/eletcric/qfinfo/Qfhow.htm.

3.2.4.1 Form No. 556

Form No. 556 lists the information required in an application for QF status. The information requirements include general contact information and a description of the facility detailing the following:

- ownership
- whether it is a small power production or cogeneration facility
- primary energy source
- power production equipment and capacity
- location

Additional information requirements include the names of the distribution companies with which the facility plans to interconnect and transmit or sell electricity to, and the names of the distribution companies or other suppliers from which the facility plans to purchase supplementary, standby, back-up, and maintenance power.

Form No. 556 is required for all new applications. Once a Form No. 556 has been filed, it may be referred to in subsequent notices of self-recertification or requests for FERC recertification. Only the revised data items need to be provided. For a copy of Form No. 556, please visit http://www.ferc.fed.us/electric/qfinfo/Part131.htm.

3.2.4.2 Self-Certification

The owner or operator of a facility that meets standards for QF status may self-certify by providing a notice to FERC. This entails filing a sworn statement that asserts compliance with technical and ownership criteria. An applicant is required to provide a completed Form No. 556 to the following:

- FERC
- distribution companies with which the QF intends to transact business
- the state regulatory commissions of the states in which these distribution companies and the QF are located

The notice of self-certification must be signed and submitted with 14 hard copies, as well as in electronic format on a 3 ½” diskette in Word Perfect format. There is no fee for the filing of a notice of self-certification. Within 10 business days, FERC will send the applicant one copy of the notice of self-certification with an assigned QF docket number. Notices of self-certification are not published in the Federal Register.

3.2.4.3 FERC Certification

Instead of filing a notice of self-certification, facilities may seek FERC certification. If successful, FERC certification results in the issuance of an order certifying the facility. The applicant filing a request for FERC certification is required to provide a completed Form No. 556 and a filing fee. The application fees as of September 16, 1999 are $12,650 for a small power production facility and $14,320 for a cogeneration facility. A filing date will not be assigned to an application unless it is accompanied by the proper fee. An applicant seeking certification is required to provide a completed Form No. 556 to the following:

- FERC
- utilities with which the QF intends to transact business
- the state regulatory commissions of the states in which these utilities and the QF are located

As with self-certification, any QF document needs to be signed and submitted with 14 hard copies, as well as in electronic format on a 3 ½” diskette in Word Perfect format. In addition, applicants for FERC certification must provide a brief notice announcing the request for certification for publication in the Federal Register - the legal news document published every business day by the National Archives and Records Administration (NARA).[11]

Within 90 days of the filing date or the submittal of supplementary information, whichever is later, FERC will do one of the following:

- notify the applicant if the application is incomplete
- issue an order granting or denying certification
- determine the time frame for issuance of an order

Any orders that deny certification will specify the criteria that are not met. If FERC has not acted upon the application within 90 days, the certification request is considered to

[11] The Federal Register contains Federal agency regulations; proposed rules and notices; and Executive orders, proclamations and other Presidential documents. For more information on the Federal Register please visit http://www.nara.gov/fedreg/.

have been granted. However, if additional information is provided by the applicant to supplement the original application, the 90-day action period begins anew with the submission date of the supplemental information.

3.2.4.4 Pre-Authorized Recertification

Qualifying facilities that need to recertify, for example those undergoing modifications, may recertify through a notice of self-recertification. This is true both for facilities that have been certified by FERC, as well as for those that have been self-certified. If FERC has certified a facility, the operators of that facility may file a notice of pre-authorized recertification to report specified changes to the facility. As discussed in 18 CFR 292.207, changes to facilities that are not considered substantial alterations or modifications and will not likely result in the revocation of qualifying status include the following for all QFs:

- a change that does not affect the upstream ownership of the facility
- a change in the installation or operation date
- a change in the manufacturer of the power generation equipment selected for the facility's installation when there is no change in capacity or operating characteristics

Changes to small power production facilities that are not considered substantial alterations or modifications and will not likely result in the revocation of qualifying status include the following:

- a decrease in the amount of fossil fuel used by a small power production facility
- a decrease in the power production capacity of a small power production facility
- a change in the primary energy source of a small power production facility, provided that the facility continues to comply with the technical requirements of a small power production facility

Changes to cogeneration facilities that are not considered substantial alterations or modifications and will not likely result in the revocation of qualifying status include the following:

- a change in the location of a cogeneration facility, or a small power production facility, if the new location would not cause the facility to violate the 80 MW capacity cap
- a decrease in the amount of natural gas or oil or any change in the amount of other fuel used by a cogeneration facility, provided that the efficiency value and the operating value calculation for the facility remain at or above the values stated when the certification or recertification order was issued
- an additional use of a cogeneration facility's thermal output, if the original uses are as stated when the certification order was issued
- an increase in the efficiency value or the operating value of a cogeneration facility
- a change in the power production capacity of a cogeneration facility if the efficiency value and the operating value calculation for the facility remain at or above the

values stated when the certification or most recent, relevant recertification order was issued

- a change in the purchaser of the cogeneration facility's thermal output, when there is no change in the specified thermal application or process

There is no fee for filing a notice of pre-authorized FERC recertification.

3.3 Selling Renewable Energy and Distributed Generation in Massachusetts

PURPA and FERC establish the framework for the certification and purchase of energy from qualifying facilities. PURPA directs each state to determine the avoided cost for each distribution company. The following section reviews existing regulations, including net metering, that regulate electricity sales from renewable and distributed generation facilities in Massachusetts.

3.3.1 Massachusetts Electric Industry Restructuring Overview[12]

On November 19, 1997, the Massachusetts Legislature passed House No. 5117, "An Act Relative to Restructuring the Electric Utility Industry in the Commonwealth, Regulating the Provision of Electricity and Other Services, and Promoting Enhanced Consumer Protections Therein." On February 20, 1998, the Massachusetts Department of Telecommunications and Energy (DTE) issued its final Order in DTE 96-100 and its "Rules Governing the Restructuring of the Electric Industry," 220 CMR 11.00. The purpose of these rules was to "provide a regulatory framework for an efficient industry structure that will minimize long-term costs to consumers while maintaining the safety and reliability of electric services with minimum impact on the environment."[13]

Since March 1, 1998, Massachusetts's consumers have had the opportunity to choose the supplier of their electric generation. The following overview of electric industry restructuring was prepared by the DTE:

It is useful to think of the electric industry as being comprised of four primary components:

- **generation**, the power plants that create the electricity that is transported to homes and facilities in Massachusetts
- **transmission**, the wires and associated facilities that transport the electricity (at high voltage levels) from power plants to distribution substations

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[12] Most of this section is taken verbatim from the Massachusetts Department of Telecommunications and Energy. *"Description of the Restructured Electric Industry."* http://www.magnet.state.ma.us/dpu/restruct/competition/index.htm#BACKGROUND.

[13] This section is taken from the Massachusetts Department of Telecommunications and Energy. "Summary of the Department's Electric Industry Restructuring Rulemaking Proceedings." http://www.magnet.state.ma.us/dpu/restruct/competition/index.htm.

- **distribution**, the wires and associated facilities that transport the electricity (at lower voltage levels) from distribution substations to customers' facilities and homes
- **customer services**, which covers, among other things, metering, billing, and information services

Prior to electric industry restructuring, the above components were bundled together and provided as monopoly services by the local electric company. Prices were fully regulated by the DTE.

As of March 1, 1998, the generation component has been unbundled from the other components of electric service. Customers are now able to purchase generation services from entities other than their local electric companies. The prices that these "competitive suppliers" of generation service may charge customers will be determined by the competitive market; these prices are not regulated by the DTE, although the suppliers participating in the competitive market are licensed by the DTE. The other components of electric service (transmission, distribution, and customer services) have not been opened to competition; instead, these components continue to be provided as monopoly services by distribution companies.

Customers' bills currently are presented in an unbundled format that shows the various components of electric service, as shown in the line items listed in Table 4. The rates and the format of the sample bill shown below are intended for illustrative purposes only; they do not represent the format or charges for any particular distribution company's bill. Below is a brief description of each line item shown on a sample unbundled bill.

Table 4: Typical Unbundled Bill Line Items		
Delivery Services		
Distribution Service	Customer charge	$6.00/month
	Energy charge	$0.035/kWh
Transmission Service	Energy charge	$0.003/kWh
Transition Costs	Energy charge	$0.025/kWh
	DSM charge	$0.0031/kWh
	Renewables charge	$0.001/kWh
Supplier Services		
Generation Service	Energy charge	$0.035/kWh

- **Distribution Service**: Very little has changed in the way that distribution service is provided to customers. Distribution service remains a monopoly service provided exclusively to customers in a particular service territory by the local distribution company. Rates for distribution service continue to be fully regulated by the DTE at levels that allow each distribution company a reasonable opportunity to recover the costs it incurs in providing this service to its customers.

- **Transmission Service**: Similar to distribution service, there is little change in the manner in which transmission service is provided to retail customers. Retail transmission rates continue to be fully regulated at levels that allow each distribution company a reasonable opportunity to recover the costs it incurs in providing this service to its customers. However, there has been significant change in the manner in which transmission service is provided at the wholesale level. In its Order 888, issued April 24, 1996, FERC mandated that owners of transmission facilities must provide transmission services to third parties on the same (or comparable) basis, and under the same (or comparable) terms and conditions that apply to their own use of their transmission system.

- **Transition Costs:** Transition charges are set at levels that allow each distribution company a reasonable opportunity to recover its fully-mitigated stranded costs. The Restructuring Act established certain categories of costs that qualify as stranded costs. For costs incurred prior to January 1, 1996, these categories are: 1) fixed generation-related costs; 2) above-market purchased power contracts; 3) generation-related regulatory assets; and 4) nuclear decommissioning costs. For costs incurred after January 1, 1996, transition cost categories are: 1) employee-related costs related to restructuring; 2) payments in lieu of taxes; and 3) removal and decommissioning costs for fossil-fuel generators.

- **Demand Side Management (DSM) and Renewable Charges**: Revenue from the DSM charges will be collected by each distribution company and will be used to fund DSM programs and activities. These programs will be administered individually by each distribution company, consistent with the manner in which DSM programs have historically been administered in Massachusetts. Revenue from the renewable charges is presently collected by each distribution company, which transfers the revenue to the Renewable Energy Trust Fund. For more information on the Renewable Energy Trust Fund please see Section 5.1.2.1.

- **Generation Service**: There are three generation service options available to consumers: 1) standard offer service, provided by distribution companies; 2) default service, provided by distribution companies; and 3) competitive generation service, provided by competitive suppliers. It is important to remember that a customer that is connected to a distribution company's system will receive electric service, regardless of the option under which the customer is receiving generation service. However, the price that the customer pays for generation service is dependent on the type of service the customer is receiving.

    - **Standard Offer Service:** is a transitional generation service that will be available to customers of record of each distribution company through 2005. A customer that did not select a competitive supplier as of March 1, 1998 automatically was placed on standard offer service (customers who move into a Distribution Company's service territory after March 1, 1998 are not eligible to receive standard offer service - these customers are placed on default service until they select a competitive supplier). In general, once customers select a competitive supplier, they are no longer eligible to return to standard offer service, with the following exceptions:
        - low-income customers can return at any time

- residential and small commercial and industrial customers can return within 120 days of selecting a supplier (this option was available only until March 1, 1999)
- customers participating in a municipal aggregation program can return within 180 days of joining the program

The rates for standard offer service are regulated by the DTE and are set at levels that provide a 10 percent overall bill reduction to customers receiving standard offer service; the level of the overall bill reduction for standard offer customers increased to approximately 15 percent on September 1, 1999.

- **Default Service:** is the generation service that is provided by distribution companies to those customers who are not receiving either competitive generation or standard offer service. Customers who move into a distribution company's service territory after March 1, 1998 will receive default service until they select a competitive supplier. Prices for default service are regulated by the DTE and may not exceed the average market price for electricity in New England.

- **Competitive Generation Service:** is provided by competitive suppliers and electricity brokers that have been licensed by the DTE. A competitive supplier is an entity that is licensed by the DTE to sell electricity and related services to customers. An electricity broker is an entity that is licensed to facilitate or otherwise arrange for the purchase and sale of electricity and related services to customers, but is not licensed to sell electricity to customers. An applicant for a competitive supplier or electricity broker license must demonstrate, among other things, its financial and technical capability to provide the applicable services. Prices for competitive generation service are set by the competitive electricity marketplace and are not regulated by the DTE. For more information on licensing as a competitive supplier and electricity broker, please see Section 4.4.

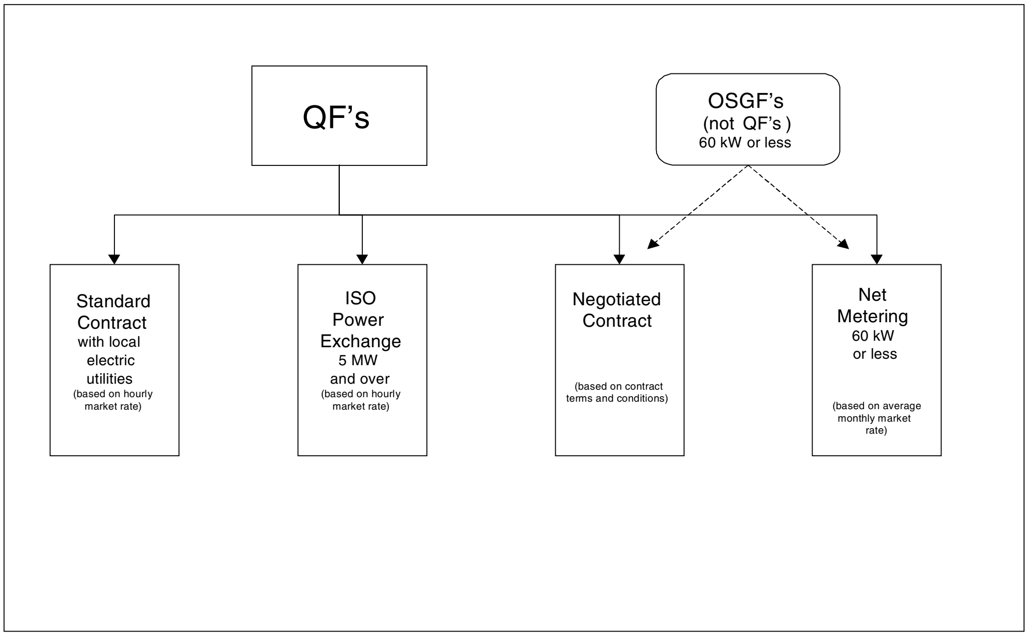
For more consumer information regarding Electric Industry Restructuring, visit the Commonwealth's Consumer Education website at http://www.state.ma.us/thepower.

3.3.2 Sales of Electricity by QFs to Electric Utilities

Producers of renewable and distributed generation are able to sell power to, as well as to buy power directly from their distribution company. Prior to restructuring, the price for a distribution company's mandatory purchase of electricity from a QF was based on a distribution company's avoided cost - the cost that it would otherwise incur to purchase or generate electricity. Consistent with electric industry restructuring in Massachusetts, on December 27, 1999, the DTE issued modified QF regulations, 220 CMR 7.00 et seq., to govern the sales of electricity by QFs and On-Site Generating Facilities (OSGFs) to electric utilities in the competitive market based on wholesale market prices.

Developers of renewable energy and distributed generation have several options for selling power based on the characteristics of their projects. These are summarized in Figure 2.

Figure 2: QF Selling Options



The Massachusetts QF regulations address the following:

- sales and purchases between QFs and OSGFs and electric distribution companies
- reporting requirements for distribution companies with respect to interconnected QFs and OSGFs

The regulations also address the distribution company's obligation to interconnect QFs and OSGFs, prescribe interconnection standards, assign cost responsibilities, and outline metering standards for QFs and OSGFs. Sections of the regulation that address interconnection and metering requirements are discussed in Section 5.0. It is important to note that during the development of a facility, efforts to interconnect with a distribution company often take place at the same time that developers of a QF are working out a contract with the distribution company and are addressing the siting and permitting issues reviewed in Section 4.0.

Massachusetts has a net metering regulation, 220 CMR 11.00, that allows for OSGFs with a capacity of 60 kW or less to receive credit for any net generation during each month. In simple terms, this allows developers of OSGFs to run their meters both forwards and backwards.

The DTE's regulations do not limit the ability of any party to agree to rates, terms, or conditions of purchase that differ from the rates, terms, or conditions otherwise required by these regulations. In addition, modified regulations do not affect an existing QF contract with regard to the sale of electricity or capacity.

In summary, a QF can sell its generation to a distribution company by:

1) a standard contract available for all sales at the short-run rate;[14]
2) a net metering arrangement if its design capacity is 60 kW or less; or
3) a negotiated contract executed by a QF and an electric distribution company or another market participant. For the full text of 220 CMR 7.00, please visit http://www.magnet.state.ma.us/dpu/electric/99-38/220finalreg.htm.

3.3.2.1 Standard Contract for QFs

Under 220 CMR 7.00, QFs are eligible to receive payments under a standard contract from the distribution company based on the ISO's power exchange market price. Based on their size, QFs have different metering capabilities. For example, larger QFs are required to have meters that measure electricity usage and consumption on an interval basis. The type of meter used at a project will impact how the ISO power exchange price is used to determine the price paid to the QF for the generation of excess electricity. Related metering requirements are discussed in Section 4.1.5.

The following outlines payments received by QFs based on standard contracts from the distribution company:

- A QF that has a capacity of 1 MW or more can have its electricity output purchased at rates based on the ISO power exchange price for hours that it generates electricity in excess of its requirements.

- A QF that has a capacity greater than 60 kW but less than 1 MW can have its excess generation output purchased at rates equal to the arithmetic average of the ISO power exchange price in the previous month.

- A QF that has a capacity of 60 kW or less can have its excess generation output purchased at rates equal to the arithmetic average of the ISO power exchange price in the previous month, or it may seek to use net metering. Net metering is discussed in Section 4.3.2.2.

Electricity purchases are adjusted to reflect the costs or savings in line losses that result from purchases from the QF. Each distribution company is required to file with the DTE its line loss factors and any supporting data. Line loss factors are determined in accordance with the NEPOOL Market Rules and Procedures.

In addition, a distribution company may be required to make payments to a QF for certain capacity and reserve products. The distribution company may be required to pay rates to the QF that are equal to the payments received for the sale of any capacity and/or reserve-

[14] The hourly wholesale market clearing price for energy and capacity as determined by wholesale market prices.

related products associated with QF output to the ISO power exchange. Eligibility to receive such payment is dependent upon an individual QFs ability to meet the particular NEPOOL requirements that govern capacity and reserve products.

Each distribution company may be required to offer a Standard Contract providing for payment at the Short-Run Rate to any QF making a request for such a contract. A QF may also sell power to an electric distribution company through a negotiated contract.

When a QF submits an offer to sell generation to a distribution company, the distribution company is required to respond within 30 days of receipt of the offer. All further exchanges are also subject to a 30-day response period. If a QF and a distribution company fail to agree to terms after 90 days, the QF may petition the DTE to investigate the reasonableness of the distribution company's actions.

3.3.2.2 Net Metering

Net metering allows for customers with small-scale generators to receive payment from distribution companies for electricity that they generate in excess of their electricity usage. The types of generators that are eligible for net metering include:

- QFs with a design capacity of 60 kW or less
- other OSGFs. (As defined in MGL 164, ss.1, 1G(g)(ii), OSGFs include any plant or equipment used to generate electricity that has a design capacity of 60 kW or less)

Many OSGFs, such as rooftop solar panels, might also qualify as QFs, but some OSGFs, such as fuel cells and micro-turbines operating on natural gas or other fossil fuels are not QFs. As long as the generator has a capacity of 60 kW or less, however, owners may elect to use net metering.

The net metering regulations, 220 CMR 11.04, allow for a distribution company's customer with a QF or OSGF of 60 kW or less to run the meter backward and receive a credit, equal to the arithmetic average of the ISO power exchange price in the previous month, in any month that the customer generates more electricity than it consumes. The credit appears on the customer's next bill, unless a customer requests a check for the credit.

Under 220 CMR 11.04, distribution companies are prohibited from imposing special fees on net metering customers, such as additional backup charges and demand charges, or requiring additional controls, such as liability insurance, as long as the OSGF meets interconnection standards and all relevant safety and power quality standards. Net metering customers must pay minimum charges for distribution service and all other regular charges for each net kWh delivered by the distribution company in each billing period. For the full text of 220 CMR 11.04 visit
http://www.magnet.state.ma.us/dpu/restruct/competition/index.htm.

3.3.2.3 Negotiated Contract

As noted earlier, the Massachusetts QF regulations do not preclude a QF from entering into a negotiated contract with an electric distribution company or other market participants such as retail power marketers.

3.3.2.4 Provision of Supplementary, Back-up, Maintenance, and Interruptible Power

Each distribution company is required to supply supplementary, back-up, maintenance, and interruptible power to QFs and OSGFs pursuant to 18 CFR 292.305(b) under rate schedules applicable to all customers, regardless of whether they generate their own power. Where it is possible for a QF or an OSGF to receive power under more than one rate schedule, the facility may choose its rate schedule.

3.3.2.5 Auxiliary Service Charges for Massachusetts Electric Company

A recent settlement agreement has occurred for the merger of National Grid USA (formerly New England Electric System) and Eastern Utilities (EUA). It stipulates that a subsidiary of National Grid USA, Massachusetts Electric (which will include the new combined service territories) would be able to adjust its distribution rates by the amount of any lost distribution revenues that the DTE finds that Massachusetts Electric has incurred due to new on-site generating capacity brought online July 1, 1999 or later. Massachusetts Electric would not adjust its rates until the total new capacity exceeds 15 MW. Once the 15 MW threshold is met, Massachusetts Electric would propose an Auxiliary Service Rate that would be charged to new on-site generating capacity that subsequently comes online.

An exemption from the Auxiliary Service Rate would be for QFs operating on a non-dispatchable basis that produce thermal energy for industrial processes or heating and cooling systems at the customer’s location, as well as non-dispatchable, renewable generation facilities. In addition, according to 220 CMR 11.07, distribution companies are prohibited from imposing special fees, such as the Auxiliary Service Rate, on net metering customers. Such exempt generators, however, would be included in the calculation of the 15 MW threshold.

Generators that can be dispatched by the ISO to respond to changes in system demand or transmission security constraints would not be exempt. Massachusetts Electric, however, would not seek to recover losses in distribution revenue associated with the first 15 MW of new on-site generation.

Once the 15 MW threshold is reached, Massachusetts Electric would work with stakeholders to develop a “mutually agreeable proposal” prior to filing a proposed Auxiliary Service Rate. In addition, if the auxiliary service charges do not fully recover lost distribution revenues in spite of the Auxiliary Service Rate, Massachusetts Electric would be able to adjust its distribution rates in each rate class for any remaining revenues (within that rate class in the preceding calendar year) as a result of new on-site generation, but only to the extent that the distribution rate remains below the regional average. The Auxiliary Service Rate would continue through December 31, 2009.

It is important to note that Massachusetts G-2 and G-3 customers (large industrial and commercial customers that are planning to install on-site generation with a capacity of 50 kW or greater) would be required to notify Massachusetts Electric at least six months prior to installation.[15]

In the final order approving the merger, DTE 99-47, the DTE did not make any findings on the Auxiliary Service Rate because it considered the issue to be outside the scope of its findings and deliberations. However, in addressing the impact of on-site generation on rates, the DTE noted that it will need to consider the following:

- how to quantify the economic impact of new on-site generation on Massachusetts Electric
- the potential impact of the auxiliary rates on the emergence of new beneficial technologies
- the extent to which revenue losses from new on-site generation should be recovered from developers of on-site generation and the ratepayers in each rate class

The Auxiliary Service Rate is still subject to review, and after a public hearing, is still subject to the DTE's approval.[16] Although subject to further rulemaking, the proposed use of auxiliary service charges for Massachusetts Electric may prompt discussion of such charges in other distribution company service territories in Massachusetts.

3.3.2.6 Examples of QF and OSGF Transactions

The following tables provide examples of transactions between a QF and a distribution company under a standard contract and a net metering arrangement.

The example in Table 5 assumes that a QF is selling electricity to a distribution company under a standard contract. Under this arrangement, the distribution company pays the QF the hourly market price for positive net generation in each hour. The QF operates for a three-hour period, and has a positive net generation each hour. The variables in this example include net generation, and the market price for each hour as determined by the ISO.

Table 5: Standard Contract Example

	Hour 1	Hour 2	Hour 3	Total
Gross Generation (kWh)	1000	1000	500	2500
Gross Consumption (kWh)	200	200	200	600
Net Generation (kWh)	800	800	300	1900
ISO Power Exchange Price (per kWh)	3 cents	4 cents	2 cents	3.3 cents (pro-rata per kWh average)
Net Revenue	$24.00	$32.00	$5.00	$62.00

[15] New England Electric System and Eastern Utilities Associates. Rate Plan Settlement. Filing Letters and Settlement Volume 1 of 2. November 29, 1999. Submitted to MA DTE, Docket DTE 99-46.
[16] DTE 99-46. Order- Issued by the Commissioners Connelly, Keating, Vasington, Sullivan. March 2000.

The example in Table 6 assumes that the QF or OSGF is eligible for, and chooses to use, monthly net metering. Under net metering, the QF sells electricity to the distribution company at the average monthly market price, and the QF purchases electricity from the distribution company at the applicable distribution company rate, which is generally higher than market price for generation because it also includes transmission and distribution costs. In this example, the QF or OSGF does not always generate enough energy to meet its own needs, and in some months it is required to purchase energy from the distribution company.

Table 6: Net Metering and Supplementary Purchase Example				
	Month 1	**Month 2**	**Month 3**	**Total**
Gross Generation (kWh)	500	600	500	1600
Gross Consumption (kWh)	600	400	400	1400
Net Generation (kWh)	-100	200	100	200
Sell Price {Arithmetic Average Monthly Power Exchange Price (per kWh)}	4 cents	4 cents	4 cents	4 cents
Purchase Price {Distribution company Rate (per kWh)}	10 cents	10 cents	10 cents	10 cents
Net Revenue	-$10.00	$7.00	$4.00	$1.00

3.3.2.7 Information Requirements

According to 220 CMR 7.03(2)(a), QFs are required to comply with any and all applicable NEPOOL and ISO information requests, rules, and requirements necessary for their generation output to be sold to the ISO power exchange by a distribution company.

Each distribution company is required to file with the DTE, for informational purposes, a report of new QF and OSGF activity for each calendar year, by April 1 of the subsequent year. The filing includes:

- the name and address of the owner, and the address where the QF or OSGF is located
- a brief description of the type of QF or OSGF
- the primary energy source used by the QF or OSGF
- the date of installation and the on-line date
- the method of power delivery to the distribution company (contract or net metering)
- the design capacity of the QF or OSGF
- a brief discussion identifying any QF or OSGF that was denied interconnection by the distribution company, including a statement of reasons for such denial

In addition, for each calendar year, each distribution company is required to file a report with the DTE that describes incremental reductions in the purchase of electricity due to customer operations of, or purchases from, on-site renewable energy technologies, fuel cells, cogeneration equipment, OSGFs; and cogeneration facilities with a capacity of 60 kW or less that are eligible for net metering. The filing is due by April 1 of the following year and shall include discussions of:

- the incremental reductions in purchases of electricity due to customer operations of, or purchases from, on-site generation
- the impact of these reduced purchases on the local distribution company's transition charge
- the effect of these reduced purchases on the company's kWh sales
- an estimate of the distribution company's lost gross revenues due to these reduced purchases
- a narrative identifying all customers that have announced plans to operate, or purchase from, on-site generation

3.3.2.8 Fines, Penalties, and Sanctions

In the event that a fine, penalty, or sanction is levied on a distribution company by NEPOOL or the ISO as a result of a QFs failure to comply with an information request, rule, or requirement, the QF is responsible for the costs of such fines, penalties, or sanctions.

If the developer or operator of a QF or OSGF finds that a distribution company is not complying with 220 CMR 7.00, it can petition the DTE to investigate the distribution company's actions. The DTE is empowered at its discretion to open an investigation, and, if it finds it necessary, to hold public hearings on the petition.

3.3.2.9 Payment for QF or OSGF Power

A QF or OSGF selling power to a distribution company can receive a check from the distribution company or have payment credited towards its bill from the distribution company.

3.4 Independent System Operator New England (ISO)

PURPA does not require QFs to sell exclusively to utilities. For technical, financial, and practical reasons, smaller renewable and distributed generation may be limited, however, to transactions with utilities. Larger facilities (5 MW or greater) operating 24 hours a day and telemetered by the ISO so that they can react and respond to dispatches, may also want to explore other markets, such as contracts with non-utilities and the spot market. The ISO is responsible for administering these wholesale markets and their transactions for energy, ancillary services (such as capacity), and transmission services.

This section provides a brief overview of the ISO and its wholesale market functions. Renewable and distributed generation developers should also visit http://www.iso-ne.com as well as contact the ISO's customer service department at (413) 540-4220 to learn more about the ISO and its market functions.

3.4.1 Background

Based in Holyoke, Massachusetts, the ISO was established on July 1, 1997 by transferring staff and equipment from the New England Power Pool (NEPOOL) to the ISO. The ISO began operation of the New England wholesale power exchange on May 1, 1999.

The ISO service territory includes 95 percent of New England's electricity load, over 27,000 MW of generation capacity, and over 5.5 million electricity customers. Electricity consumption in the territory exceeded 115 TWh in 1996.

Prior to establishment of the ISO, NEPOOL operated the regional transmission grid. NEPOOL was formed in 1971 as a voluntary association of New England electric utilities that wanted to establish a single regional network for coordinating major generating and transmission facilities.

NEPOOL continues as an organization, representing both traditional electric utilities and other companies that participate in the emerging competitive wholesale electricity marketplace. The ISO presently has a services contract with NEPOOL to operate the bulk power system and administer the wholesale marketplace. Under this contract, standards and policies for system reliability, market rules, and dispute resolution are established by mutual consent of NEPOOL and the ISO. Under emergency conditions, the ISO has the temporary power to unilaterally establish or change rules as deemed necessary to ensure system reliability or competitiveness in the marketplace. This agreement provides the ISO with authority to operate the generation and transmission systems and the wholesale electricity spot market. Many of the ISO functions are subject to FERC jurisdiction.

3.4.2 Organization

Organizational responsibilities are divided into two major areas: System Operation and Reliability and Marketplace Operations.

The System Operations and Reliability component includes the following responsibilities:

- conducting daily dispatch of electricity resources
- assuring the reliability of the power system
- administering the open access transmission tariff for New England
- facilitating short and long-term forecasting and reliability planning

The Market Operations component complements the former by:

- overseeing operations of the residual wholesale electricity marketplace to ensure that fully competitive markets are created that will lead to the lowest pricing for bulk electricity
- providing customer services and training support to utilities and other companies participating in the competitive marketplace as well as to others
- monitoring the marketplace to ensure fairness for participants
- formulating and updating the ISO rules and procedures
- developing and updating power exchange computer applications and support
- performing marketplace settlement to ensure compensation of spot market sellers by spot market buyers and to track bilateral contracts between market participants

The overall organizational design is meant to ensure an appropriate level of interface between the System Operations and Market Operations functions so that a healthy, competitive marketplace exists and system reliability is maintained.[17]

3.4.3 NEPOOL Membership

Large renewable generators that do not want to contract with their local utilities may want to join NEPOOL. This would enable them to participate directly in the wholesale electricity market. Membership in NEPOOL is open to any entity that buys, sells, transmits, or distributes electricity. Membership is also available to end-user customers that are eligible to have the ISO provide them directly with high voltage transmission services.

The membership process begins with submission of a membership application. Decisions regarding NEPOOL membership are made by the NEPOOL Participants Committee Membership Subcommittee (NPCMS). The NPCMS reviews materials and approves applications for subsequent filing with FERC. The filing is then reviewed by FERC, and a public notice of the filing is published. If there are no problems with the filing, FERC typically sends a letter of approval to NEPOOL within two months of the filing date.

NEPOOL Participants who join NEPOOL in any sector other than "End-User" are required to pay a $5,000 application fee, an annual fee of $5,000, and a variable monthly fee for service that weights load responsibility, ownership of bulk power supply facilities, market activities, and other factors. The monthly variable charge varies widely, based upon business activity.

3.4.4 Capacity Requirements

As set forth by the NEPOOL Regional Market Operations Committee,[18] facilities greater than 5 MW may participate in the ISO-administered markets. These facilities may offer their generation output directly into the spot market or submit to the ISO a schedule of their generation output and contractual obligations. Under new DTE regulations, facilities smaller than 1 MW cannot directly receive spot market compensation for their output. Facilities between 1 MW and 5 MW have the option of participating in the ISO wholesale market if they have the appropriate metering.

According to the ISO, it must limit facilities smaller than 1 MW because the ISO market system unit commitment program cannot recognize bids in increments less than 1 MW. The generation output of small QFs, whether netted from load or reported as generation, becomes part of each market player's daily settlement (which is the matching of dedicated generation resources and load obligations) with the ISO. It is important to note that the ISO is currently working on a system that would allow smaller generation

[17] ISO-NE. *A New Organizational Structure.* www.iso-ne.com/about_the_iso/organizational_structure.html.
[18] The NEPOOL Regional Market Operations Committee established these options in actions taken on August 6, 1998 and September 25, 1997.

facilities to have their generation recognized by the ISO for record-keeping purposes. The facilities would still remain non-dispatchable, meaning that they would not be able to bid into the system.[19]

3.4.5 General Types of Transactions

In addition to the standard contract with the local distribution company, renewable developers may choose to negotiate or contract with other market participants as well. The following describes four types of wholesale market electricity transactions that can take place in the ISO wholesale market:

- **Unit:** The buyer of electricity under a unit contract has entitlement to a specified portion of the generation from a specified unit. Unit contracts may be long or short-term bilateral contracts between two parties.

- **System:** System transactions are contracts between two companies that do not specify a specific unit that is obligated to serve the contract, and, as such, are "portfolio" contracts. The duration of contracts will vary. System transactions are also usually in the form of bilateral contracts.

- **Spot Market:** The ISO operates an hourly power exchange that matches buyers and sellers of electricity and related services. This means that wholesale electricity suppliers and generators bid their resources into the market and submit separate bids for each resource for each hour of the day. The ISO tabulates the bids and stacks them in dollar terms from lowest to highest matching the expected hourly demand forecast for that hour and each hour in the next day. The ISO then determines the least cost dispatch sequence for the next day, which reflects the actual bids. Generators will then be dispatched to match the actual load occurring on the system. The highest bid resource that was dispatched to meet actual load sets the "market clearing price" for electricity. This is the price that will be paid to all suppliers by buyers who purchase power from the spot market.[20]

- **External Transactions:** External transactions involve either imports or exports with companies that are not located within the NEPOOL control area.

3.4.6 Electricity Market Operations

The ISO operates a day-ahead, hourly marketplace according to a single settlement system. Electricity is traded on the power exchange on an hourly basis. The power exchange is a residual market, where the difference between a participant's energy resources

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[19] Paul Peterson, ISO-NE. "Coordinating RPS, GPS, and Disclosure Policies." Massachusetts Electric Industry Roundtable Presentation. March 24, 2000.
[20] ISO-NE. "How Does the Marketplace Work?" http://www.iso-ne.com/about_the_iso/marketplace.html.

and its obligation is traded through the ISO. Generators and dispatchable loads that meet minimum technical requirements are able to participate. Bids are submitted in $/MWh the day before their effective date. Transactions are priced according to the Energy Clearing Price (ECP) -- the highest bid price that is dispatched within a given one hour trading interval. Payments/receipts are simply the product of MWh bought/sold and the ECP. The day-ahead bids are used for scheduling, but prices are determined ex post facto based on real-time dispatch. The single settlement system consists of the following steps:

- Wholesale electricity suppliers and generators submit bids and schedule the previous day, submitting separate bids for each resource for each hour of the day.
- The ISO schedules bids for the next day to minimize total production costs, based on the bids, forecasts, operating and transmission constraints, and bilateral schedules.
- The ISO may accept schedule changes up to an hour before real time, but day-ahead bids are binding and may not be changed.
- The ISO dispatches generators in real time at least cost, based on bids, bilateral schedules, and forecasts for subsequent hours.
- The highest bid dispatched to meet actual load establishes the market clearing price. This price is paid by buyers who purchase power from the residual or spot market.

In the future, the power exchange will transition to a "multi-settlement" system. Under a multi-settlement system, day-ahead bids are used for both scheduling and day-ahead transactions, and only deviations from the day-ahead schedule are priced ex post facto. The multi-settlement system consists of the following steps:

- Bids for both generation and loads are submitted the previous day.
- The ISO schedules bids for the next day to minimize costs, based on the bids, forecasts, operating and transmission constraints, and bilateral schedules.
- The ISO determines prices associated with the day-ahead schedule, which, together with the schedule quantities, are used in the first settlement.
- The ISO may accept bids/schedule changes up to two hours before real time.
- The ISO dispatches generators in real time at least cost, based on bids, bilateral schedules, and forecasts for subsequent hours.
- The ISO determines real-time spot prices based on actual dispatch; deviations from the day-ahead schedules are settled at real-time prices (second settlement).

Under a single settlement system, all commitments and transactions are settled at prices established in real time. As a result, bidders have an incentive to make adjustments that influence the spot market price after the day-ahead schedule is formed. Since the spot price is used for all trades, there is significant incentive for manipulation. Under a multi-settlement system, the potential for gaming decreases.

FERC's conditional approval of NEPOOL's market rules requires NEPOOL at some point in the near future to implement a multi-settlement system. Such a system will provide large end-users with the opportunity to bid load curtailments into the market, so that they will be able to make money by agreeing to use less electricity for certain periods of time when supplies are tight.

NEPOOL operates bid-based markets and charges market-derived rates in seven markets -- one for energy and six for ancillary services.[21] Ancillary services may also be purchased and sold through the ISO. These other services include a Ten Minute Spinning Reserve Market, a Ten Minute Non-Spinning Reserve, a Thirty Minute Operating Reserve Market, an Installed Capability Market, an Automatic Generation Control Market, and an Operable Capability Market.[22]

Between 90 and 95 percent of the ISO's business activity and operating revenues are derived from the power exchange.[23] The ISO is now able to run the region's competitive wholesale electric energy, capacity, and ancillary services markets for organizations participating in NEPOOL. The system uses data from bidding, bilateral contracts, metering, and dispatch for settling markets and billing associated with these services.

3.4.7 Transmission System Operations and Pricing

The ISO is responsible for dispatch of electricity resources, maintaining reliability of the bulk power system, and administering the open access transmission tariff for New England. Other responsibilities include short-term and long-term demand forecasting and reliability planning. A generator of renewable energy or distributed generation can apply for transmission services if it is a member of NEPOOL, or if it contracts with a member of NEPOOL to use transmission services. For a copy of the Application for NEPOOL Transmission Services under the NEPOOL Open Access Transmission Tariff, please visit http://www.ne-iso.com.

An Internet-based Open Access Same-Time Information System (OASIS) has been designed to provide participants with real-time information about the transmission system. Participants use OASIS to reserve transmission services. Through OASIS, participants forecast, calculate, and post total transfer capacity, available transfer capacity, available ancillary services (including reserves and generation control), and all associated price information.

The ISO administers a system-wide transmission tariff that specifies the terms, conditions, and prices of transmission services.

Regional transmission service is provided for pool transmission facilities. Most pool transmission facilities rated 69 kV and above qualify for regional network service. Under the ISO’s two-stage regional network service pricing strategy, a system average tariff will be phased-in over 10 years. In the interim, each transmission customer for regional network service pays an access charge based on the revenue requirements of the transmission operator where final delivery occurs. Transmission service costs are a uniform rate determined by

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[21] Cramton, P. and Wilson, R., Market Design, Inc. *A review of ISO New England's Proposed Market Rules,* a report commissioned by ISO New England. September 9,1997. Further information provided by *Frequently asked questions: Customer services and training.* http:www.iso-ne.com.

[22] It should be noted that NEPOOL might be eliminating the Operable Capability Market in the future.

[23] Cramton, P. and Wilson, R., Market Design, Inc. *A review of ISO New England's Proposed Market Rules*, a report commissioned by ISO New England. September 9, 1997. Further information provided by *Frequently asked questions: Customer services and training*.

calculating the actual costs for building and maintaining transmission facilities. The rate is reviewed and approved by FERC. The regional network service zonal rate is adjusted by an amount up to 30% in either direction, based on the point of delivery, and a local network access charge, as applicable. The local network access charge offers local network service and local point-to-point service for generators located in a NEPOOL member's service area that are connected to non-NEPOOL facilities and need non-NEPOOL facilities to reach the NEPOOL grid.

The ISO also offers non-firm, point to point service for through or out transmission service. Through transmission service describes an import of electricity that is either used in the region or passes through the region to another region. Out transmission service reflects an export of power. Through or out transmission service customers pay a single system weighted average rate based on the pool transmission facilities of the transmission operators.

Local network service is provided for non-pool transmission facilities under each transmission operator’s open access tariff. Local network customers pay a single, "postage stamp" rate (the same for all customers) based on the non-pool transmission facility costs.

In addition, the ISO tariff contains additional rates, charges, terms, and conditions for the administrative services that are carried out by the ISO. Services are categorized as follows:

- **Schedule 1:** Scheduling, system control, and dispatch
- **Schedule 2:** Energy administration service
- **Schedule 3:** Reliability administration service (RAS)

The rates and charges for each service are based on the allocated portion, or budget amount, of the year's total budgeted expense, as adjusted for true-ups. The portion of the budget amount allocated to each service consists of direct costs (e.g., personnel, software, and equipment), as well as a percentage of the ISO's general and administrative costs (determined by dividing the direct costs of that service by the direct costs of all services).

If the ISO determines during the year that collections for all services will exceed 105 percent of the budget amount for that year, the ISO will file an amended tariff or rate schedule with FERC. For services listed under Schedule 1 and 2, deviations between collections under the tariff and the ISO's actual expenses will be reconciled through an annual true-up process. Before the close of the calendar year, the ISO will compute the total actual expenses to date and the projected expenses of providing each service to year-end, and compare these totals with those charges actually collected under the tariff. Based on these comparisons, the ISO will adjust, up or down, the projected revenue requirement for the following calendar year. From these figures, the ISO will determine its rates for the following calendar year and will make a rate change filing to reflect the foregoing analysis.

Charges for Schedule 3 reflect actual monthly expenses for RAS and are thus not subject to true-up. The provision discussed in the preceding paragraph limiting total collections to 105 percent of the budget amount effectively limits amounts collected for RAS under Schedule 3.

Revenues collected through the tariff do not attempt to recover initial working capital for the ISO. Any debt service for reimbursing NEPOOL for restructuring costs, including costs related to separation of NEPOOL staff and design, installation, and implementation of the Power exchange, are to be recovered through other contractual arrangements to be filed with FERC.[24]

3.4.8 Congestion Management

Congestion management involves measures -- such as price signals or the redispatch of generation -- that are taken to mitigate congestion that may occur when there is not enough capacity on a transmission line to deliver electricity to a given location. In a non-congested electricity market, prices vary by time, not by place. Although transmission congestion historically has not been a significant obstacle in the New England market, congestion may become more of an issue in the future as more generating facilities are developed and greater demands are placed on the system. Owners of distributed generation, however, will not be placing intense demands on the system and will not have to worry as much about congestion management since they will be able to produce all or a portion of their power themselves.

In July 1999, FERC approved NEPOOL's preliminary congestion management plan, although it is not yet in effect. Using a location-based marginal pricing approach, generators will be paid nodal energy prices, and loads will pay zonal energy prices equal to the weighted averages of the nodal prices in each zone. Zonal pricing uses a fixed rate for broad geographic areas, under which the transmission customer pays one rate based on the zone where energy is withdrawn, regardless of how many other zones are crossed. On the other hand, nodal pricing specifies a tariff from one point to another point in the network. Implementation of the congestion management plan is scheduled for 2001.

For centralized power exchange transactions, suppliers will be paid the location price for power they provide (location price × MW), and buyers will pay the applicable location price for power delivered (location price × MW). The location price for generators is calculated where generation is injected into the grid. Prices paid by loads will be calculated from zones where power is withdrawn. Power exchange customers will also be responsible for differences of location energy prices associated with congestion.

Those who self-schedule or use bilateral contracts will only be responsible for charges associated with congestion and losses. The application of these charges reflects transactions in the single settlement market.

Congestion occurs when there is not enough transmission capacity to deliver low-priced energy to a load in a given zone. As a result, higher priced energy from within the zone must be dispatched. The marginal cost of supplying load in each zone is reflected by location price. Location price will be determined by the bids of generators and suppliers in the central market taking into account the energy flows across the transmission grid. The

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[24] ISO-NE. *FERC Tariff For Transmission Dispatch and Power Administration Services.* http://www.iso-ne.com.

ISO will publish the hourly location price for each load zone. Congestion for customers in the power exchange will be calculated by the difference between the location price of the load and of the generator multiplied by the quantity of energy in the transaction between the two paths. This formula will also be used to determine the cost of congestion for bilateral contracts along the same path.

Losses will be determined as the marginal loss component of location prices at the point of withdrawal minus the component at the point of injection. Losses for exports and through transactions will be calculated using flow distributed ratios at each of the zones over which the transaction passes.

In order to hedge against the risks associated with congestion costs, Financial Congestion Rights (FCRs) may be obtained in advance by market participants. Both bilateral and power exchange transactions will be subject to congestion costs; these costs may be locked in with the purchase of FCRs. Each FCR represents a 1 MW transmission transaction over a predetermined path. If they own FCRs consistent with their day ahead and real-time commitments, customers with FCRs will then only pay for whatever marginal losses there may be.

3.5 Qualifying to Sell Power to Retail Customers

Renewable energy and distributed generators may contract with retail suppliers and brokers or even sell power directly to retail customers. The following section provides an overview of the requirements for selling electricity to retail customers in Massachusetts.

As specified in 220 CMR 11.00, suppliers that want to sell electricity to retail customers and brokers who want to arrange retail electricity sales need to apply for a license with the DTE. Each application for a license must be notarized, signed, and accompanied by the following information:[25]

- legal name, business address, and a description of the company's form of ownership
- a statement saying that acting as a supplier or broker is not beyond the scope of the company
- a summary of any history of bankruptcy, dissolution, merger or acquisition of the entity during the two calendar years immediately preceding the application
- name, title, and toll-free telephone number of the contact person available to customers
- name, title, and telephone of the regulatory contact person
- name and address of the Resident Agent for Service of Process in Massachusetts
- a brief description of the nature of the business being conducted, including types of customers and geographic area to be served
- a statement that the applicant will comply with information disclosure requirements
- documentation concerning purchases of power contracts

[25] This information should not be construed as a complete list of requirements, but is only intended to provide an overview. For a complete list of requirements, refer to 220 C.M.R. 11.04.

- documentation of the technical ability to otherwise generate or obtain and deliver electricity and/or other proposed services
- documentation of financial capability
- documentation that the applicant is a NEPOOL member or will meet transaction requirements through a contractual arrangement with a NEPOOL participant
- evidence of attendance at a training session sponsored by the DTE
- a sample bill demonstrating familiarity with billing requirements
- a statement concerning whether any of the applying company's officers have been convicted of certain felonies within the last five years
- a sworn statement that all the information in the application is true

Applicants for licensing as brokers are not required to include information regarding NEPOOL membership status, or compliance with the disclosure and labeling requirements. Each applicant is required to pay an annual filing fee of $1000. The DTE informs applicants within 20 days of the submission of a complete application whether a license has been granted or not. Licenses are valid for one year.

Suppliers and brokers are also subject to regulations, contained in 220 CMR 11.00 et seq., concerning the retail customer enrollment process, billing, termination, information disclosure and labeling, and complaint and damage resolution. Failure to comply with the above regulations may result in suspension revocation or non-renewal of a license. The Electronic Business Transaction Standards Working Group Report provides standard operating procedures and protocols for electronic transactions among market participants. For more information on the Electronic Business Transaction Standards Working Group, please visit http://www.eua.com/ebtlist.html.

For more information on licensing to sell power to retail customers, visit http://www.magnet.state.ma.us/dpu/restruct/ competition/index.htm. For a copy of the application, visit http://www.magnet.state.ma.us/dpu/restruct/96-100/appform.pdf.

4.0 Siting and Environmental Permitting Processes

Renewable energy and distributed generation developers must comply with federal, state, and local regulations pertaining to facilities siting and environmental permitting.

4.1 State Permits and Approvals

State permits and approvals, including Energy Facilities Siting Board (EFSB) approval, Massachusetts Environmental Protection Act (MEPA) certification, and Massachusetts Department of Environmental Protection (DEP) permits, and the Massachusetts Office of Coastal Zone Management (CZM) federal consistency review are outlined below.

It is suggested that developers visit the regional DEP for a pre-application informational meeting about permitting. The developer will learn more about threshold levels of the MEPA, and the DEP will help the developer identify the necessary DEP agency permits. The DEP's regulatory process, including links to regulations and policies, as well as the actual permit applications, can be downloaded from www.state.ma.us/dep/energy/pergen.htm.

Compliance with MEPA is a crucial component of the siting process. Under MEPA, an Environmental Impact Report (EIR) is required for projects that meet certain threshold levels (detailed below in Section 4.1.2.1). An EIR is meant to serve as a comprehensive report of the air, water, land, solid waste, and other environmental impacts that might be caused by a project. A developer will need to examine the MEPA thresholds for different issues, such as size, capacity, water use, etc., to determine whether the scope of its project might exceed specific thresholds and thus require an EIR.

A developer will not be able to gain a DEP permit without MEPA certification and the approval of the EFSB. MEPA certification is issued by the Secretary of the Executive Office of Environmental Affairs. Some small projects may turn out not to exceed MEPA thresholds and may only need to address local permitting issues, but will still be subject to local requirements such as zoning and wetlands restrictions. The state siting and permitting process (as well as a hypothetical timeline for the QF process and interconnection) is summarized in Figure 3. The timeline reflects a "best case" scenario. Please note that the time estimates are hypothetical, and that timelines for each process are likely to vary significantly from project to project.

Figure 3: Hypothetical "Best Case" Project Timeline

Month	1	2	3	4	5	6	7	8	9	10	11
QF Process and Contract Development	FERC QF Certification Process			QF Contract Begins (earliest possible date, obviously facility would need to have completed other processes and have begun operations)							
	DTE QF Contract Process										
Interconnection and Metering	Notification and Studies			Interconnection might begin (longer for transmission interconnection)							
EFSB Process		Petition to Construct		Hearings						Approval	
MEPA Process	File ENF	File ENF, comment period, and regulatory action		Prepare Draft EIR		File Draft EIR, comment period, and regulatory action		Prepare EIR		File EIR, comment period, and regulatory action	
DEP Permits (project specific)						Prepare and file Permit, comment period, and regulatory action					
Other State Agencies (project specific)											
Federal Permits (project specific)											
Local Permits (project specific)											
Community Involvement	Ongoing										

4.1.1 Energy Facilities Siting Board

The EFSB is an independent state review board within the Massachusetts Department of Telecommunications and Energy (DTE). The EFSB reviews large-scale energy facility projects, i.e., projects capable of producing 100 MW or more at gross capacity. The EFSB review process therefore may not be relevant to most renewable energy facility developers. The structure and responsibilities of the EFSB are set forth in Massachusetts General Laws, Chapter 164, Sections 69G through 69R, and in the Code of Massachusetts Regulations at 980 CMR 1.00 – 11.00. According to state statute, the EFSB has the responsibility to ensure “reliable energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost."

The nine-member EFSB is made up of three commissioners of the DTE, the Secretary of Environmental Affairs, the Director of Economic Development, the Commissioner of the Division of Energy Resources, and two public members who are appointed to three-year terms by the Governor. Decisions issued by the EFSB are directed by the governing statutes and based on the precedent of previous EFSB decisions.

A developer will not be able to commence construction of a generating facility unless a petition for approval of construction of that generating facility has been approved by the EFSB. In addition, no state agency of the Commonwealth will issue a construction permit for any such generating facility unless the petition to construct such generating facility has been approved by the EFSB pursuant to this section.

A developer may contact the EFSB hearing officer at (617) 305-3525 or visit http://www.state.ma.us/dpu/siting_board.htm for more information.

4.1.1.1 Jurisdictional Criteria

The EFSB accomplishes its mandate through review of jurisdictional intrastate energy facility proposals by developers and intervention in FERC review of interstate energy facilities. The EFSB reviews projects that meet at least one of the following criteria:

- capable of producing 100 MW at gross capacity
- includes new electric transmission lines in an existing transmission right of way with a design rating of 115 kilovolts or more, and ten miles or more in length (does not apply to interstate suppliers)
- includes new electric transmission lines in a new transmission right of way with a design rating of 69 kilovolts or more, and one mile or more of length
- includes ancillary structures built by the developer for the sole purpose of serving the needs of the facility. There are no size thresholds for ancillary structures. Any new facilities, including roads, natural gas, oil, sewer, water lines, etc., are subject to EFSB jurisdiction.

4.1.1.2 Approval to Construct – Application and Review Process

Developers of electric generation facilities that fall under EFSB jurisdiction based on the above criteria must petition the EFSB for an Approval to Construct. A petition to construct a generating facility should include the following information:

- a description of the proposed generating facility, including any ancillary structures and related facilities
- a description of the environmental impacts and the costs associated with the mitigation, control, or reduction of the environmental impacts of the proposed generating facility
- a description of the project development and site selection process used in choosing the design and location of the proposed generating facility
- evidence that the expected emissions from the facility meet the technology performance standard[26] in effect at the time of filing, or a description of the environmental impacts, costs, and reliability of other fossil fuel generating technologies, and an explanation of why the proposed technology was chosen
- any other information necessary to demonstrate that the generating facility meets the requirements for approval specified in this section

[26] The technology performance standard is a set of 22 actual numbers established to measure the amount of pollutants emitted by power plants under 980 CMR 12.00 in August 1997.

Prior to filing, developers are encouraged to review previous facility decisions and to meet with EFSB staff for guidance with respect to the scope of review and procedures. A filing fee is required for all generation projects.

The EFSB review is a three-phase process:

- During the procedural phase the EFSB requires notice of the proceeding, holds public hearings, and determines the parties who may participate.
- In the evidentiary phase, the information requests are issued, written testimony is filed, and evidentiary hearings are held.
- During the decision phase briefs are filed and a final decision is issued by the EFSB.

EFSB review of a petition is based on statute, regulations, and standards developed in previous cases, applied consistently to all facilities, as appropriate. Review is conducted at two levels: project level and facility level.

- **Project Level:** At the project level, EFSB staff will consider the need for, cost of, and environmental impacts of transmission lines, natural gas pipelines, facilities for the manufacture and storage of gas, and oil facilities. For these projects, the EFSB will also consider a comparison of alternatives, as well as project viability based on its financial soundness, construction feasibility, operability and fuel acquisition sources. For these projects, the EFSB will review the project's environmental impacts and the need for and cost of such facilities.

- **Facility Level:** The review at the facility level includes an examination of the site and/or route selection and comparisons of the proposed site and alternatives on the basis of cost and environmental impacts. However, cost-based review does not take place for a generation facility, consistent with the Commonwealth's policy of allowing market forces to determine need and cost for generation facilities.

For generation plants, after public notice and a period for comment, the EFSB will issue and revise its own list of guidelines. Sufficient data will be required from the developer to enable the EFSB to review the local and regional land use impact, local and regional cumulative health impact, water resource impact, wetlands impact, air quality impact, solid waste impact, radiation impact, visual impact, and noise impact of the proposed generating facility. The data will include:

- a description of the location of the generating facility to be constructed
- a summary of the studies conducted by the applicant detailing the environmental impact of the generating facility and a statement of the reasons for its choice of the location
- a statement setting forth the reasons for the application (including licenses, permits, and other regulatory approvals required by law for the facility's construction)

Within 60 days of the filing of a petition to construct a generating facility, the EFSB will conduct a public hearing in the locality in which the generating facility would be located. In addition, the EFSB will, within 180 days of the filing, conduct public evidentiary hearings on each petition.

4.1.1.3 Override Authority

The EFSB has the authority to grant a Certificate of Environmental Impact and Public Need to a previously approved facility that is prevented from being constructed as a result of delays, inconsistencies, or conditions imposed by other state or local agencies. The issuance of a Certificate overrides other state or local authorities. To date only two Certificates have been issued.

4.1.1.4 Illustration of the Sequence of the EFSB Process

Table 7 illustrates the sequence of events for a filing for EFSB review.

Table 7: EFSB Process
• Applicant meets with EFSB to discuss proposed project.
• Applicant files petition. A filing fee is required for non-utility projects.
• EFSB Staff requires the applicant to publish a public notice detailing the proposed and alternate site/route. The notice is published in local newspapers to ensure residents and abutters are informed.
• EFSB Staff visit proposed and alternative sites.
• EFSB Staff conducts a public hearing in proposed and alternate site areas. A minimum of three weeks must elapse between publication of the notice and the public hearing. The public hearing is the first opportunity for local residents to comment on the project.
• Thirty days after the filing is submitted, public hearing notices must be received from parties wishing to be intervenors or interested parties in the adjudicatory proceeding. Late petitions for intervention will be considered by the EFSB on a case-by-case basis.
• One or more prehearing conferences may be held to rule on motions regarding intervention, establish the ground rules, and other related issues.
• One or more rounds of information requests are made by EFSB Staff or intervenors. (The first round of information requests may precede the prehearing conference.)
• Formal adjudicatory hearings are held to establish a complete record for the case. The hearing sessions are typically held every other day.
• EFSB Staff, the applicant, and the intervenors make Record Requests throughout the hearing.
• The record is closed; the applicant and the intervenors file summary briefs.
• EFSB Staff prepares a tentative decision. The tentative decision may recommend approval, approval with conditions, or rejection of the proposed project.
• Prior to a scheduled meeting of the EFSB the tentative decision is delivered to all parties. Parties have seven days in which to make comments on the tentative decision. The EFSB normally meets on scheduled monthly meeting dates, if it has new business.
• The EFSB meets to discuss the tentative decision; applicant and intervenors may be present and may contribute to the discussion. The EFSB then votes. They may adopt, adopt with amendments, or return the tentative decision to EFSB Staff for further work.
• Assuming the decision is adopted, parties have 30 days to file a notice of appeal before the Supreme Judicial Court. Absent such notice, the EFSB decision is final.

4.1.2 Massachusetts Environmental Policy Act

The Massachusetts Environmental Policy Act (MEPA), c. 30, ss. 61-62H, requires Massachusetts state agencies to determine the impact on the environment of all works, projects, or activities conducted by them, as well as private projects that come before them, and to use all practicable means and measures to avoid or minimize the environmental harm that has been identified. The staff of the Secretary of Environmental Affairs, headed by the Assistant Secretary for Environmental Impact Review (also known as the MEPA Director), is responsible for daily implementation and administration of the MEPA review process.

A project is subject to MEPA if it requires any state agency action, financial assistance, land transfer, or permit, and also meets any of the thresholds listed in 301 CMR 11.03 (discussed below). A QF or OSGF developer should speak with a MEPA staff person to verify whether its project is subject to MEPA.

If the project is subject to MEPA, a form known as an Environmental Notification Form (ENF) must be completed. The ENF provides a description of a proposed project. The Office of Environmental Affairs reviews the ENF and then decides whether a more detailed analysis, known as an Environmental Impact Report (EIR), is necessary.

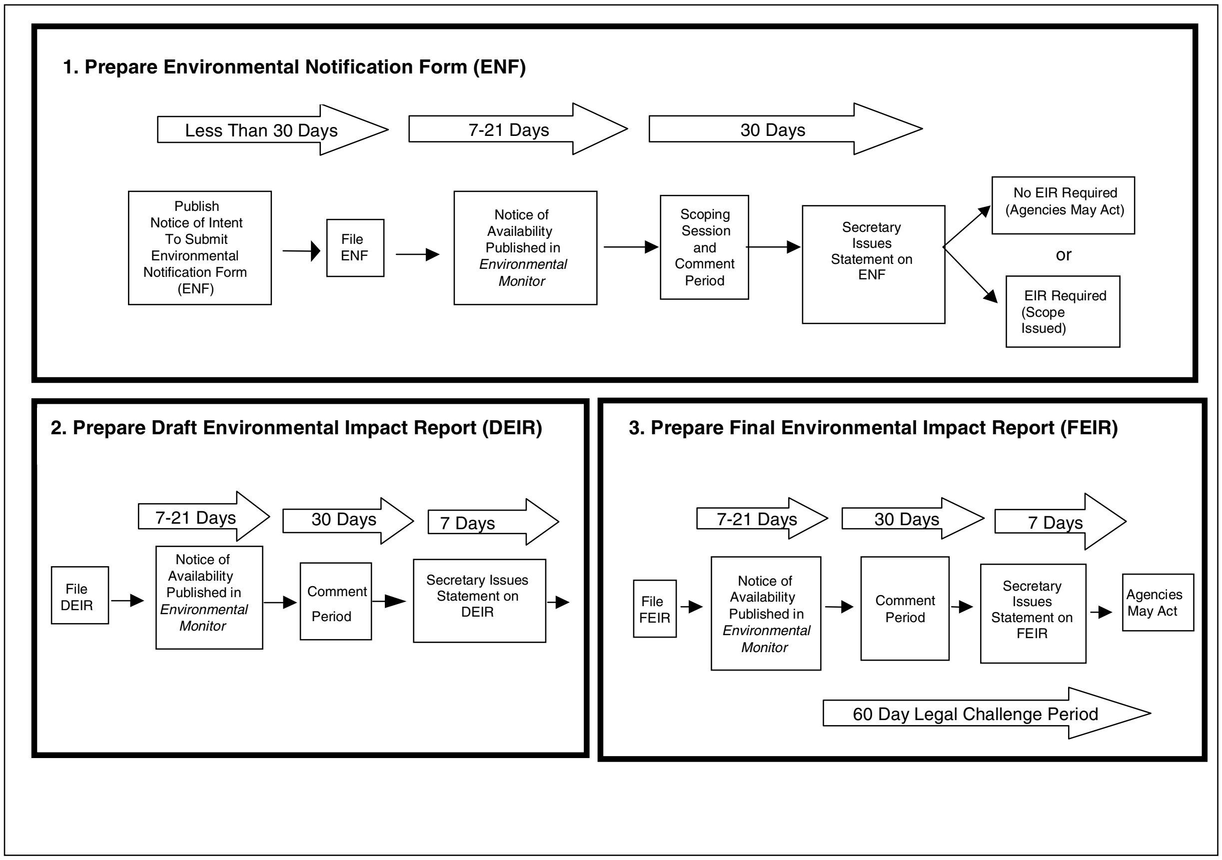
An EIR is a much more comprehensive description of the project, its technologies, the potential environmental impacts associated with the project, and possible alternatives. A project likely to have a significant environmental impact will generally require an EIR.

The MEPA statute establishes standards for review and a basic procedural outline for conducting that review. Details of the review process are set forth in revised MEPA regulations (301 CMR 11.03) promulgated on June26, and which became effective on July 1,1998. The MEPA regulations establish project thresholds, procedures, and a timetable for a two-step review process.

As with the EFSB, some smaller renewable energy and distributed generation projects may not require MEPA review. Developers should review the MEPA criteria and confirm with MEPA and other state officials prior to moving forward with their projects.

For more information on MEPA and related forms and policies please visit http://www.state.ma.us/mepa.htm. The MEPA process and "best case" timeline are summarized in the following figure.

Figure 4: MEPA "Best Case" Timeline



4.1.2.1 Review Thresholds

MEPA establishes review thresholds that identify general categories of projects or certain characteristics related to a project's nature, size, or location that may cause damage to the environment, either directly or indirectly, and therefore require MEPA review. A MEPA review is required when one or more review thresholds are met or exceeded and the subject matter of at least one review threshold is within MEPA jurisdiction.[27]

The review thresholds do not apply to a lawfully existing structure, facility, or activity; routine maintenance; or a replacement project. Some of the categories that may affect a QF or OSGF are discussed below. However, a QF or OSGF developer should also

[27] Even if these thresholds are not met, a process exists by which the Secretary of Environmental Affairs can be asked to require MEPA review. Under this process, known as the "fail-safe" provision, two or more agencies, or ten or more persons, can ask the Secretary to require review. In order to require review under this provision, the Secretary must make certain specified findings about the significance of real harm that could be caused by the project and the unforseeability of that harm when the thresholds were established. If the Secretary requires that a project be reviewed pursuant to the fail-safe provision, it proceeds as a normal review.

go to http://www.state.ma.us/mepa/301_1103.htm to view the complete list of thresholds set forth in 301 CMR 11.03, which contain a number of relevant caveats and exceptions.

The review thresholds specifically mention certain types of energy projects for which an ENF and other MEPA review may be required if the Secretary so requires. Specific projects mentioned include:

- construction of a new electric generating facility with a capacity of 25 or more MW
- expansion of an existing electric generating facility by 25 or more MW
- construction of a new fuel pipeline five or more miles in length
- construction of electric transmission lines with a capacity of 69 or more kV, provided the transmission lines are one or more miles in length along a new, unused, or abandoned right of way

The review thresholds also note that in addition to an ENF, a full-fledged EIR will be required for:

- construction of a new electric generating facility with a capacity of 100 or more MW
- expansion of an existing electric generating facility by 100 or more MW
- construction of a new fuel pipeline ten or more miles in length
- construction of electric transmission lines with a capacity of 230 or more kV provided the transmission lines are five or more miles in length along a new, unused, or abandoned right of way

Energy projects that do not fall under these energy-related criteria, however, may still require some form of MEPA review if they meet other criteria that govern projects in general rather than energy projects specifically. These criteria include the following:

- **Land:** Various factors will determine whether a project would sufficiently impact land-related issues so as to require an ENF and/or an EIR. While the exact language of the regulations should be reviewed, in general, most projects that would directly alter 25 or more acres of land, transform active agricultural land, create at least five acres of impervious area[28], involve land that had been held for natural resources purposes or for conservation, preservation, agricultural or watershed preservation purposes, or involve an urban renewal plan, will require some form of MEPA review.

- **Rare species:** Some form of MEPA review will be required if the project might alter designated significant habitat or might involve the taking of an endangered or threatened species or species of special concern provided that the project site is two or more acres and includes an area mapped as a Priority Site of Rare Species Habitats and Exemplary Natural Communities.

- **Wetlands, waterways, and tidelands:** Some form of MEPA review (ENF or EIR) will be needed if the project involves alteration of: 1,000 or more square feet of salt marsh or outstanding resource waters; 5,000 or more square feet of bordering or

[28] An impervious area is one that water cannot penetrate, such as pavement.

isolated vegetated wetlands; a coastal dune, barrier beach, or coastal bank; or 500 or more linear feet of bank along a fish run or inland bank. MEPA review will also be needed for a new or expanded fill or structure (except a pile-supported structure) that is in a velocity zone or regulatory floodway; for alteration of one half or more acres of any other wetlands; or where a variance is being sought from the wetlands laws.

In addition, MEPA review will be necessary if the project involves dredging of 10,000 or more cubic yards of material, or disposal of 10,000 or more cubic yards of dredged material unless at a designated in-water disposal site. MEPA review will also be necessary if a new utility line is being sought to provide service to a structure on a barrier beach, or if a new dam or significant alteration of an existing dam is being proposed; or if there is expansion or construction of a new or existing solid fill structure of 1,000 or more square feet base area or of a pile-supported or bottom-anchored structure of 2,000 or more square feet base area (except for certain types of floats).

If a Chapter 91 License[29] is required, MEPA review will be needed for a new or expanded non-water dependent use provided the use occupies one or more acres of waterways or tidelands, unless the project is an overhead utility line, a structure of 1,000 or less square feet base area accessory to a single family dwelling, a temporary use in a designated port area, or an existing unlicensed structure in use prior to January 1, 1984.

- **Water:** Some form of MEPA action (an ENF and possibly an EIR) is necessary for a project involving the new or expanded withdrawal of 100,000 or more gallons per day from a water source that requires new construction for the withdrawal or involves the new or expanded withdrawal of 500,000 or more gallons per day from a water supply system above the lesser of current system-wide authorized withdrawal volume or three-years' average system-wide actual withdrawal volume. MEPA action is also needed for projects involving the construction of one or more new water mains five or more miles in length, or projects involving alterations requiring a variance in accordance with the Watershed Protection Act.

  An ENF and mandatory EIR will be required in the case of a new or expanded withdrawal of 2,500,000 or more gallons per day from a surface water source; 1,500,000 or more gallons per day from a groundwater source; or a new inter-basin transfer of water of 1,000,000 or more gallons per day or any amount determined significant by the Water Resources Commission.

- **Wastewater:** Some form of MEPA action will be needed for a project involving construction of one or more new sewer mains that will result in an expansion in the flow to a wastewater treatment and/or disposal facility by 10% of existing capacity; will be five or more miles in length if the sewer mains are located in the right of way

[29] Under Massachusetts General Law, Chapter 91 protects the public's interest in waterways for recreation and wetlands protection. In effect, a Chapter 91 license is required if there will be any alterations to the water or surrounding area. Further details of these requirements are outlined in section 4.1.3.4 Division of Wetlands and Waterways.

of existing roadways; or 1/2 or more miles in length, provided the sewer mains are not in the right of way of existing roadways.

In addition, MEPA review will be needed for the new or expanded discharge to a sewer system of 100,000 or more gallons per day of sewage, industrial wastewater, or untreated stormwater; or to a surface water of 100,000 or more gallons per day of sewage, 20,000 or more gallons per day of industrial wastewater, or any amount of sewage, industrial wastewater or untreated stormwater requiring a variance from applicable water quality regulations; or to groundwater of 10,000 or more gallons per day of sewage within an area, zone, or district established, delineated, or identified as necessary or appropriate to protect a public drinking water supply, an area established to protect a nitrogen sensitive embayment, an area within 200 feet of a tributary to a public surface drinking water supply, or an area within 400 feet of a public surface drinking water supply; or 50,000 or more gallons per day of sewage within any other area; or 20,000 or more gallons per day of industrial wastewater; or any amount of sewage, industrial wastewater or untreated stormwater requiring approval by the Department of Environmental Protection of a variance from Title 5 of the State Environmental Code for new construction.

Any project involving new or expanded capacity for the combustion or disposal of any amount of sewage sludge, sludge ash, grit, screenings, or other sewage sludge residual materials or involving the storage, treatment, or processing of 50 or more wet tons per day of sewage sludge or sewage sludge residual materials will also require some form of MEPA review.

Construction of a new wastewater treatment and/or disposal facility with a capacity of 100,000 or more gallons per day or expansion of an existing facility by the greater of 100,000 gallons per day or 10% of existing capacity will also trigger some form of MEPA review.

An EIR may be necessary for projects involving the new interbasin transfer of wastewater of 1,000,000 or more gallons per day or any amount determined significant by the Water Resource Commission; the discharge of any amount of sewage, industrial wastewater, or untreated stormwater directly to an outstanding resource water; or for certain larger-scale projects described in the Regulations.

- **Transportation:** Some form of MEPA review will be required for the construction of a new roadway one-quarter or more miles in length, or the widening of an existing roadway by four or more feet for one-half or more miles, unless the project consists solely of an internal or on-site roadway or is located entirely on the site of a non-roadway project.

  In addition, MEPA review will be needed for a project involving the construction, widening, or maintenance of a roadway or its right-of-way that will alter the bank or terrain located ten more feet from the existing roadway for one-half or more miles (unless necessary to install a structure or equipment), cut five or more living public shade trees of 14 or more inches in diameter at breast height, or eliminate 300 or more feet of stone wall.

MEPA action also will be needed if a project involves construction of 300 or more new parking spaces at a single location, the generation of 2,000 or more new average daily traffic (adt) counts on roadways providing access to a single location, or the generation of 1,000 or more new adt on roadways providing access to a single location and construction of 150 or more new parking spaces at a single location, or the abandonment of a substantially intact rail or rapid transit right-of-way.

- **Air:** Some form of MEPA review will be needed for a project involving construction of a new major stationary source with, following construction and the imposition of required controls, a potential for arriving at or exceeding federally regulated emissions standards of: 100 tons per year (tpy) of particulate matter as PM10, CO, lead, or SO2; 50 tpy of VOC or NOx; 10 tpy of any Hazardous Air Pollutant (HAP); or 25 tpy of any combination of HAPs.

  MEPA review will also be needed for a project involving the modification of an existing major stationary source resulting in a "significant net increase" in actual emissions, provided that the stationary source or facility is major for the pollutant, emission of which is increased by: 15 tpy of particulate matter as PM10; 100 tpy of carbon monoxide (CO); 40 tpy of sulfur dioxide (SO2); 25 tpy of volatile organic compounds (VOC) or nitrogen oxides (NOx); or 0.6 tpy of lead.

  In addition to an ENF, an EIR will be required for projects surpassing certain higher emission levels.

- **Solid and Hazardous Waste:** An ENF and other MEPA review will be required for a project that involves new capacity or an expansion in capacity for the combustion or disposal of any quantity of solid waste, or the storage, treatment, or processing of 50 or more tons per day of solid waste, unless the project is exempt from site assignment requirements. This often involves landfills, transfer stations, etc., but might also involve trash-to-energy facilities. If a permit is required in accordance with MGL c. 21D, MEPA review will also be required for new capacity or an expansion in capacity for the storage, recycling, treatment, or disposal of hazardous waste. A full-fledged EIR will generally be required as well for projects creating greater volumes of solid waste unless they fall under certain types of exceptions.

- **Historical and Archaeological Resources:** A project being developed on an historical or archaeologically significant site is likely to require MEPA review. Specific criteria may be found in the Review Thresholds. If unexpected, potentially significant discoveries are made during excavation, such as human remains or other objects, the Massachusetts Historical Commission must be contacted.

- **Areas of Critical Environmental Concern (ACEC):** If a proposed project is to be located within an Area of Critical Environmental Concern (ACEC), an ENF and possibly other MEPA review will be required, even if the project does not meet any of the other review thresholds. To determine whether one's site is located in such an ACEC, a developer should contact the Department of Environmental Management (DEM). DEM oversees an atlas of maps showing Areas of Critical Environmental Concern.

4.1.2.2 Review Process

If a renewable energy or distributed generation project is subject to MEPA jurisdiction and either meets or exceeds one or more review thresholds listed above, or is required by the Secretary to undergo fail-safe review, the developer initiates MEPA review by preparing and filing an ENF with the Secretary. ENF submittal deadlines are twice per month, on the fifteenth and the last day of the month. The ENF is distributed by the developer to state agencies, local officials, and regional planning agencies. To find out which specific agencies, officials, or regional planning agencies to send it to, the developer may ask MEPA staff, or visit MEPA's web page at http://www.state.ma.us/mepa. Copies of the ENF must be furnished free of charge to anyone who requests a copy during the review period. A Public Notice of Environmental Review must also be published by the applicant in a local newspaper prior to submittal of the ENF.

The Secretary publishes the appropriate pages of the ENF in the next *Environmental Monitor*, which is used to provide notice of all submissions received by the Massachusetts Executive Office of Environmental Affairs.[30] A 30-Day review period follows, during the first 20 days of which agencies, the public, the MEPA Office (which ordinarily conducts a site visit and public consultation session), and the Secretary review and comment on the ENF. At the close of the review period for an ENF, the Secretary decides whether to require an EIR.

If the Secretary does not require an EIR, MEPA certification is granted, and an agency, such as the DEP, may grant permits to the developer (see 301 CMR 11.05 and 11.06).

4.1.2.3 Environmental Impact Report Preparation Process

If the Secretary requires an EIR, the developer generally first prepares a draft EIR (DEIR). Before the developer begins work on the DEIR, the Secretary issues a document called a "scope" which provides a description of alternatives to be considered in the EIR, environmental effects to be analyzed, and techniques to be used in the analysis. The developer has up to three years to complete this report. Submittal dates for the draft EIR are the fifteenth and the last day of the month. In almost all cases, the developer prepares both a draft and final EIR. Both are subject to 30 days of public and agency comment after

[30] The *Environmental Monitor* provides public notice of filings of Environmental Notification Forms (ENFs), Environmental Impact Reports (EIRs), and Notices of Project Change (NPCs); the comment deadlines for those documents; the date and substance of the Secretary's decisions; and other useful information. *The Monitor* is published twice per month; deadlines for submission are the fifteenth and the last day of each month. In the event the deadline falls on a Saturday, Sunday or Holiday, the new submission date becomes the following business day. The date of publication of *the Monitor* determines deadlines for public comment and action by the Secretary. *The Monitor* is sent, free of charge, to all persons who request a subscription in writing to the MEPA Office.

publication in the *Environmental Monitor*. The Secretary then has seven days to issue a determination as to whether the EIR is adequate.

As a general rule, the draft EIR should provide basic information and data about the project, any alternatives, expected impacts, and proposed mitigation measures. The final EIR should respond to the Secretary's decision on the draft and the comments received, provide additional data or analyses as required, and finalize commitments on mitigation. After completion of the review of the final EIR and expiration of a legal challenge period, agencies may act on the project.

Under certain conditions (such as where only one, non-complicated state permit is needed) a developer may be allowed to submit one single EIR rather than both a draft and final EIR. In such circumstances, the developer might submit a more extended ENF, receive comments, and then proceed to a single EIR. A developer should consult with MEPA if it wishes to pursue this course.

4.1.2.4 Notice of Project Change

If changes are made to a proposed project plan, or if more than three years have elapsed between filing an ENF and a single EIR or a final EIR, the developer must file a Notice of Project Change. The developer must file a Notice of Project Change if five years have passed between the filing of a single or final EIR and the beginning of construction on a project. It is up to the Secretary to determine if the change or lapse of time significantly impacts environmental impact and if further MEPA review is required.

The continuation of a project by a new developer does not by itself constitute a change in the project, provided that the new developer adopts all mitigation measures to which the previous proponent committed. The "Notice of Project Change" must specify in detail any change in the information provided in any previous review document.

4.1.2.5 Waiver of MEPA requirements by Secretary of Environmental Affairs

The Secretary may waive any provision or requirement in 301 CMR 11.00 not specifically required by MEPA and may impose appropriate and relevant conditions or restrictions, provided that the Secretary finds that strict compliance with the provision or requirement:

- would result in an undue hardship for the developer, unless based on delay in compliance by the developer
- would not serve to avoid or minimize damage to the environment

4.1.3 Massachusetts Department of Environmental Protection

The Massachusetts Department of Environmental Protection (DEP) is a state agency responsible for protecting human health and the environment by ensuring clean air and water, the safe management and disposal of solid and hazardous wastes, the timely cleanup of hazardous waste sites and spills, and the preservation of wetlands and coastal resources. DEP is one of five agencies under the Executive Office of Environmental Affairs. DEP's role under Article 97 of the Massachusetts Constitution is to be the guarantor of "clean air and water" as well as "the natural scenic, historic, and aesthetic qualities of the environment."

If MEPA certification is necessary, the DEP may not grant a permit until certification is complete. The DEP's "DEP Permitting: A Catalog and User's Manual" lays out the entire DEP permitting process, including application fees, review timelines, public comment criteria, annual compliance assurance fees, permit duration, and transferability.[31] The manual is available at http://www.state.ma.us/dep/files/permits/intromg.htm. "Permitting" is used in this manual in its most expanded definition to include permits, registrations, approvals, authorizations, licenses, certifications, and certain required submittals. Permits may or may not have fees, and may be required of a facility, site, operation, location, or individual.

If the project or permit requires the filing of an Environmental Notification Form (ENF) under MEPA, the developer should submit an ENF no later than, and preferably well before, any permit application to DEP. DEP cannot issue any permit until the MEPA review has been completed. Also, because a project may undergo changes during the MEPA review, DEP needs to wait for the conclusion of that review before it can complete its own technical review. Many permitting requirements, however, can be addressed at least preliminarily during the MEPA review, which may help save time in the subsequent DEP review. To facilitate this process, DEP often participates actively in the MEPA review.

Certain DEP permits fall under the Timely Action and Fees Provisions. Applicants for these permits, including those who may be fee-exempt,[32] must complete, sign, and submit to the agency a transmittal form for permit application and payment, and the application form(s) for the appropriate category. Payment must be in the form of a check made payable to the Commonwealth of Massachusetts. Under DEP's Provisions, if DEP fails to approve or deny an application before its designated decision time expires, DEP is required to refund 100 percent of the application fee. DEP's money-back-guaranteed timeline is a reliable indicator of when the applicant will know whether its proposed activity or project can proceed as planned. If the application is administratively complete when first submitted, and if the information provided is technically sufficient, DEP must approve or deny the application, on its merits, before the end of the timeline for the category of permit being sought. Thus, it is in the applicant's best interest to submit an accurate and complete application. If an application has administrative or technical deficiencies, a second review period will be required, thereby extending the timeline for a final decision.

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[31] Perhaps the most helpful feature of "DEP Permitting: A Catalog and User's Manual" is a Facilities Matrix that lists, by Standard Industrial Classification (SIC) Code, most types of facilities, operations and sites that are common in Massachusetts and require one or more environmental permits or approvals. By locating the applicable SIC Code and cross-referencing the matrix, the developer may learn where in the publication to turn for permitting information. The matrix also covers a number of activities for which there is no SIC code.

[32] The following entities are exempt from the payment of application fees: cities, towns, counties, districts, municipal housing authorities, and federally recognized Indian tribe housing authorities. State agencies are exempt from payment only when the application fee is $100 or less.

While not required in most cases, a Public Comment Review Period (PC) must be conducted for certain permit categories so that DEP may consider public comment before making a final determination on a proposed application. DEP may ask the applicant for additional information during the PC Review. Upon completion of this Review (completion in most cases comes within 30 days of the closing of the public comment period), the agency will either approve or deny the application.

For most generation projects, the DEP divisions that will most likely be involved in environmental evaluation and issuance of permits are the Bureau of Resource Protection and the Bureau of Waste Prevention.

The Bureau of Resource Protection is responsible for identifying significant inland and coastal water resources, and devising strategies for protecting them. Within this Bureau, the Watershed Management Division administers the following programs:

- Wetlands and Waterways Program
- Water Pollution Control Program
- Drinking Water Program

The Bureau of Waste Prevention institutes programs to prevent pollution before it happens. The divisions are structured as follows:

- Planning and Evaluation Division
  - Air Program Planning Unit
  - Waste Program Planning Unit
- Business Compliance Division

More information about DEP permits and related policies can be found in Appendix Four and Five.

4.1.3.1 Wetlands and Waterways Program

Through its Wetlands and Waterways Program, the Watershed Management Division of the Bureau of Resource Protection ensures the protection of inland and coastal wetlands, tidelands, great ponds, rivers, and floodplains. It regulates activities in coastal and wetland areas, and contributes to the protection of ground and surface quality, the prevention of flooding and storm damage, and the protection of wildlife habitat. It administers and enforces:

- the Wetlands Protection Act (MGL c. 131, ss. 40)
- the Public Waterfront Act (MGL c. 91), which is designed to protect public rights in Massachusetts waterways
- the Coastal Wetlands Restriction Act (MGL c. 130, ss. 105)
- the Inland Wetlands Restriction Act (MGL c. 131, ss. 40A)
- the 401 Water Quality Certification Program (314 CMR 9.00)

Massachusetts General Law Chapter 91 protects the public's interest in waterways of the Commonwealth. It ensures that public rights to fish, fowl, and navigate public waterways are not unreasonably restricted, and that unsafe or hazardous structures are repaired or removed. Chapter 91 also protects a waterfront property owner's ability to approach his land from the water. In addition, Chapter 91 helps protect wetlands resource areas by requiring compliance with the Wetlands Protection Act. According to the Wetlands Protection Act (MGL c.131, s.40), the developer must obtain a Chapter 91 license, issued directly from the DEP, if there will be any alterations to any bank, riverfront area, fresh water or coastal wetland, beach, dune, flat, marsh, meadow, or swamp bordering on the ocean or on any estuary, creek, river, stream, pond, or lake, or any land subject to tidal action. Types of structures that may require licensing include: piers, wharves, floats, retaining walls, revetments, pilings, bridges, dams, and some waterfront buildings (if on filled lands or over the water). The developer may also need a new license if there will be a structural change or change in use of a previously licensed structure.

Except for a few activities exempt from the regulations, the Wetlands Protection Act prohibits the dredging, filling, or altering of wetlands without the issuance of an Order of Conditions from the local Conservation Commission. To obtain an Order of Conditions, the developer must submit an application ("Notice of Intent") to do work in a regulated area. The thresholds for working in a coastal area as well as on inland wetland resources are established in 310 CMR 10.00. Requests for variances from the regulations must follow the full permitting process, including denials from the local Conservation Commission and the regional office of the DEP.

4.1.3.2 Water Pollution Control Program

Under its Water Pollution Control Program, the Watershed Management Division of the Bureau of Resource Protection has the duty and responsibility under the Massachusetts Clean Waters Act (MGL c. 21, ss. 26-53) to enhance the quality and value of water resources and to establish a program for prevention, control, and abatement of water pollution. In this effort, it regulates wastewater treatment facilities and issues permits regulating surface and groundwater discharges. Additionally, it is responsible for sewer connection and extension permits, and for water quality certification with respect to federal permitting of water issues.

While certain types of activities require substantial presentation of water quality data, there is a short form available for stream crossings and certain minor wetlands impacts (relevant to small-scale hydro projects). An assessment of the proposed work must accompany the application, including a copy of the Order of Conditions and notification of MEPA compliance, prior to action on a Water Quality Certification. Following submittal of the application, The Water Pollution Control Program has 30 days to accept the filing as complete. There is no regulated time frame for a final decision.

4.1.3.3 Drinking Water Program

The Drinking Water Program within the Watershed Management Division has the duty and responsibility under the Massachusetts Water Management Act (MGL c. 21G) to cooperate in the planning, establishment, and management of programs to assess the uses of water in Massachusetts and to plan for future water needs. The Watershed Management Division enforces the Water Management Act by regulating water withdrawals within the Commonwealth, and oversees the protection of all proposed surface or groundwater sources to ensure the availability of a safe and adequate source of water for the public. The Drinking Water Program protects public water supply sources by preventing bacterial or dangerous chemical contamination of public water supplies.

While water withdrawal permits may not be relevant to most renewables (permits are required for withdrawals in excess of 100,000 gallons per day), they may be pertinent to prospective hydro projects and larger cogeneration projects.

The term dam means any artificial barrier, including appurtenant works, that impounds or diverts water, and:

- is twenty-five feet or more in height from the natural bed of the stream or watercourse measured at the downstream toe of the barrier, or from the lowest elevation of the outside limit of the barrier, if it is not across a stream channel or watercourse, to the maximum water storage elevation, and/or

- has an impounding capacity at maximum water storage elevation of fifty acre-feet or more. The term dam does not include any barrier that is six feet in height or less, regardless of storage capacity, or which has a storage capacity at maximum water storage elevation of fifteen acre-feet or less, regardless of height

No person may construct or materially alter a dam without a permit from the DEP. The permit is required to be recorded in the registry of deeds prior to construction. The application for a permit shall be accompanied by plans, specifications, and related documents certified by a registered professional civil engineer approved by the DEP.

4.1.3.4 Air Program Planning Unit

The purpose of the Air Program Planning Unit, within the Bureau of Waste Prevention is to protect Massachusetts' air quality resources and to reduce the public's exposure to air pollution from sources located both inside and outside the Commonwealth. The program concentrates on controlling ambient emissions of air pollutants, including emissions of toxic compounds, from stationary sources (e.g., utility and industrial) and mobile sources (e.g., motor vehicles) that contribute to violations of federal ambient air quality standards. These standards are set to protect public health with a margin of safety. The Air Program Planning Unit administers regulations under 310 CMR 5.00 to CMR 7.00 that pertain to the control of ambient air pollution.

Comprehensive DEP permitting procedures require all facilities with a heat rating input of 3 million Btu/hr (Higher Heat Value) or greater to obtain an Air Plans Approval. DEP will issue an Air Plans Approval if and only if the facility complies with:

- a case-by-case determination for use of the best available control technology
- federal ambient standards and the state ambient guidelines

A developer must demonstrate that new emissions, after the application of controls, will not cause or contribute to violation of federally enforceable ambient standards and state guidelines.

As part of the Air Plans Approval process, the DEP also reviews noise impacts of the facility at off-site locations. These noise guidelines may be most pertinent to certain renewables, such as wind power, and to larger turbine generator projects. A facility will be considered to be in compliance with the 310 CMR 6.10(1) regulation if noise from that facility does not increase the broad band noise level in excess of 10 dBA above ambient, or produce a pure tone condition.[33] For facilities that will operate on a 4-hour per day minimum basis, this policy is enforced including the period of lowest expected residual noise levels (i.e. weekday or weekend nights). Developers are encouraged to keep noise increments as far below the 10 dBA limit as is feasible. Noise limitations are also most often subject to local regulations that may be more stringent than those of the DEP. The DEP does not enforce noise regulations; the state has broad guidelines that are then controlled by individual municipalities and local boards of health. More information on noise pollution policy can be found at www.state.ma.us/dep/energy/noispol.htm.

4.1.3.5 Waste Program Planning Unit

The Waste Program Planning Unit is charged with securing the safe and efficient management of the Commonwealth's solid waste and hazardous waste streams. Developers are also subject to the Business Compliance Division on matters of Solid and Hazardous Waste.

The Solid Waste Management Act (MGL c. 111 s. 150A) regulates the handling and disposal of solid waste in Massachusetts. Facilities that use refuse, waste wood, or other solid wastes as fuel for generating power and thermal energy may need to obtain permits as solid waste management facilities pursuant to the Solid Waste Management Act. Two procedures are involved: a site assignment from the local Board of Health and an operating permit from the Business Compliance Division. Under the statute, any facility handling or disposing of solid wastes, including combustion facilities, requires a valid site assignment from the local Board of Health. Under the site assignment regulations, 310 CMR 15.00, a project proponent simultaneously files an application with the local Board of Health and the DEP.

If non-waste wood is to be used in a combustion plant, a solid waste permit is not required, but an air permit is still necessary. Waste wood is defined as any wood from construction and demolition activities. Wood chips, on the other hand, are not considered solid waste because they are derived from clean trees. Further clarification of which woods can be burned can be obtained from the DEP's Division of Business Compliance.

As of the date of publication of this Guidebook, there are proposed revisions to the Site Assignment Regulations at 310 CMR 15.00 and proposed Amendments to the Solid

[33] Ambient noise is background noise; a puretone is the sound pressure level that exceeds the normal sound levels by 2 octaves and 3 or more decibels. An example of a puretone is a squeaky motor or a screeching fan.

Waste Management Facility Regulations at 310 CMR 19.00. Although they have not yet been enacted, they may have an impact on the site assignment application and review process.

The responsibilities of the Waste Program Planning Unit also extend to the development and establishment of:

- a list of hazardous wastes
- criteria and standards for the identification of hazardous wastes
- provisions for waiver by the DEP for any waste that the DEP determines is insignificant as a potential hazard to public health, safety, the environment, or for the handling, treating, storing, use, processing, or disposal of which is adequately regulated by another governmental agency, consistent with regulations promulgated under the Resource Conservation and Recovery Act (RCRA)[34]
- standards and requirements for the treating, storing, transporting, use, and disposal of such hazardous waste
- standards and regulations for the recovery of resources from such hazardous waste

DEP Hazardous Waste regulations are found in 310 M.R. 30.00 and are promulgated under the authority granted by MGL c. 21c, ss. 4 and 6; MGL c. 211, ss 6; and Section 47 of Chapter 548 of the Acts of 1986.

According to federal and state regulations, fly ash waste, bottom ash waste, slag waste, and flue gas emission control waste generated primarily from the combustion of coal or other fossil fuels are not considered hazardous, and thus are not subject to Hazardous Waste Regulations (310 CMR 30.104(9)). Used oil is considered hazardous waste and, depending on quantity, may require a DEP permit and an EPA identification number.

4.1.4 Massachusetts Office of Coastal Zone Management

The Executive Office of Environmental Affairs (EOEA) is the state agency primarily responsible for protecting and conserving natural resources in Massachusetts. Through its offices and departments, the EOEA implements a variety of programs to protect and enhance the coastal and inland environmental resources of the Commonwealth. The Massachusetts Office of Coastal Zone Management is a program within the Office of the Secretary of Environmental Affairs. CZM advises the Secretary on matters of state coastal policy and administers the state's coastal management program.

The Massachusetts Coastal Zone Management (CZM) Program was created in response to the federal Coastal Zone Management Act (CZMA) of 1972. The CZMA established a voluntary program that gives coastal states the funding and the opportunity to develop and implement plans to manage coastal resources. The National Oceanic and

[34] RCRA gave the EPA the authority to control hazardous waste, including its generation, transportation, treatment, storage, and disposal. More information about RCRA can be found at www.epa.gov/epahome/laws.htm.

Atmospheric Administration (NOAA) Office of Ocean and Coastal Resources Management, the federal agency that administers the CZMA, has established a flexible framework that enables states to develop strategies that meet their specific needs within their state governmental structure. The CZMA also gives states the authority to review any federal action, including direct federal activities; federal licenses or permits; outer continental shelf exploration, development and production activities; and federal funding, that may affect the land or water resources or uses of the Massachusetts coastal zone for consistency with its program policies.

Under the recent deregulation of electrical generating facilities, CZM retains the authority to require analyses of alternative sites to ensure that any energy project in or affecting the coastal zone is consistent with its policies. Developers with location plans within CZM' areas of authority should be certain to check with CMZ regulations

In 1977 CZM and the Energy Facilities Siting Board (EFSB) entered into a Memorandum of Understanding in which the EFSB agreed to act consistently with CZM policies. The two agencies continue act in close cooperation.

The Coastal Zone Management Program regulations may be found at 301 CMR 20:00: Coastal Zone Management Program and CMR 21.00: Federal Consistency Review Procedures. The regulations and guidance for federal consistency applicants may be found at www.state.ma.us/czm.

CZM federal consistency review is required if the proposed project affects any land or water use or natural resource of the coastal zone, or requires a federal license or permit, is federally funded, is a direct activity of a federal agency, or is an OCS exploration, development or production activity. CZM looks to established environmental review thresholds to gauge when projects significantly affect the coastal zone and cooperates with federal agencies to develop general permits for projects of minimal environmental impact. In addition, CZM participates actively in the MEPA review process and applicants will generally be made aware of any CZM policy concerns through that procedure.

Upon determination that a project is subject to CZM consistency review, the applicant must send the following materials to CZM:

- a copy of the final MEPA Certificate, if applicable
- a copy of federal license applications
- a federal consistency certification that the proposed project is consistent with CZM policies and a justification of that statement in light of the applicable CZM program policies

Once CZM receives the application material, a notice inviting public comment is published in the *Environmental Monitor,* which commences a 21-day comment period. CZM may complete its federal consistency review after the close of public comment and upon issuance of all other applicable state environmental licenses and permits. For direct federal activities, CZM must complete its review within 60 days of receipt of application; for federal licenses or OCS activities, CZM must complete its review within six months of receipt of a complete application. If, by the end of the review period, CZM cannot concur that a project proposal is consistent with its policies, it must object to the applicant's federal consistency certification (this happens very rarely, if at all).

Upon completion of CZM's review, all applicable federal licenses and permits may be issued.

4.1.5 Massachusetts Natural Heritage Program (MNHP)

The MNHP, a division of EOEA's Department of Fisheries, Wildlife and Environmental Law Enforcement, oversees, via the MEPA process, preservation of rare or endangered species of wildlife or vegetation. The developer should consult with the MNHP during the preparation of an ENF to indicate whether a project may affect rare or endangered vegetation or wildlife.

The MNHP may require that the developer obtain a Conservation Permit to significantly alter habitat, according to CMR 321 s. 10.36, if the project will potentially impact endangered species.

4.1.6 Department of Public Safety

Projects that include storage tanks for oil or other flammable fluids such as ammonia require additional permits. Oil storage facilities greater than 10,000 gallons require approvals from both the Commissioner of Public Safety and the Division of Inspection Engineering Section of the Department of Public Safety (DPS). Local fire department approval is required prior to submitting an application for state approval of flammable fluid storage tanks under the State Division of Fire Prevention and Building Department permit process. Submission of plans and specifications for the storage tank is required as part of the state application.

With regard to fire prevention issues, below-ground and above-ground storage tanks that are less than 10,000 gallons must receive approval only from local fire authorities, under the State Division of Fire Prevention. Regulations on oil storage facilities are in MGL c. 148, ss. 9, 13, and 37; and 527 CMR 9.00 and 12.00. Above-ground storage tanks are regulated by 520 CMR 12.00.

4.1.7 Executive Office of Transportation and Construction

The Executive Office of Transportation and Construction (EOTC) reviews projects that may affect transportation via the MEPA process. EOTC receives a copy of the submitted ENF and may comment as part of the MEPA process. The Department of Public Works (DPW), under authority of MGL c. 81, ss. 21 and EOTC, issue permits for new street approaches and driveways (curb cuts).

Of relevance to energy facilities, EOTC reviews proposed methods of transportation of fuel to the site. For facilities located near a railroad line, proponents are advised to consider the potential for use of rail transportation of solid or liquid fuels to reduce the number of trips to the site made by trucks.

EOTC also reviews projects to be constructed on or near railroad property. A permit is required for construction on railroad property or land formerly used as a railroad right-of-way, pursuant to MGL c. 40, ss. 54A. No permit can be issued by a city or town for construction on such property without obtaining the consent of EOTC.

Applications for the entrance of new streets onto a state highway layout require evidence of acceptance by a local planning board or other authorized city or town official. The Highway Engineer from the appropriate District DPW office should be consulted for further application requirements.

4.1.8 Massachusetts Historical Commission

The Massachusetts Historical Commission (MHC) is the state historic preservation office and is authorized by MGL c. 9, ss. 26-27C to identify, evaluate and protect the Commonwealth's important historic and archaeological resources. Many projects, including those that require review under MEPA, are subject to review by the MHC. The developer should consult with the MHC prior to submission of an ENF for a determination of potential project impact on an area of historic or archeological significance. Regulations relevant to this issue can be found at 950 CMR 71.00.

Once excavation has begun at a particular site and an unexpected, potentially significant discovery is made, there are two procedures to follow. First, if human remains are found then the project is subject to the Massachusetts Unmarked Burial Law (Chapter 659 of the Acts of 1983 and Chapter 386 of the Acts of 1989). This law requires that the regional medical examiner be contacted immediately, who will then either have a criminal investigation conducted if the remains are less than 100 years old, or will turn the situation over to the State Archaeologist. Second, if archaeological artifacts or other objects are recovered, then the National Historic Preservation Act substitutes for state law.

Power facilities that are regulated by FERC are subject to s. 106 of the National Historic Preservation Act (36 CFR 800). This is a federal law that is delegated to each state. The MHC provides comments on FERC-regulated facilities under this regulation.

4.2 Public Involvement in State Approval Processes

As with all energy generation projects, the public involvement process is important. In many cases, the public will influence whether a proposed project is approved or not. The DEP, MEPA, EFSB, and CMZ have all established minimum guidelines for public involvement in the siting of energy facilities. The public has a right to have its interests considered in permitting decisions. Public meetings, workshops, and interviews are means of obtaining this input.

The public involvement process for each project will vary depending on the public's interest, the permitting process, and the project developer. For instance, developers may use newspaper, radio, direct mail, community fliers, and other methods to educate the public about their projects. In addition, developers may want to hold meetings or workshops (in addition to formal hearings) to share information, exchange views, and correct misunderstandings.[35]

Likewise, permitting agencies may opt to hold hearings or notify potentially affected persons. Some methods of public involvement may be the responsibility of the individual developer.

[35] "National Wind Handbook"; http://www.nationalwind.org.

4.2.1 Department of Environmental Protection

DEP minimum guidelines include a Public Comment Review period, generally lasting 21-30 days, during which time the DEP may hold hearings. Hearings will depend on the nature of the siting and permitting issues associated with the project.

4.2.2 Massachusetts Environmental Policy Act (MEPA)

As discussed earlier in this Guidebook, if certain review thresholds are met, MEPA requires that a developer first fill out an Environmental Notification Form (ENF) that briefly describes its intended project. The ENF must then be published in the *Environmental Monitor.* No sooner than 30 days prior to and no later than the date that the ENF appears in the *Environmental Monitor,* the developer must publish a notice of the filing of the ENF in a newspaper of local circulation in each municipality affected by the project, or in a newspaper of statewide circulation if an affected municipality is not served by a local publication. This notice must be provided using a form available from the MEPA Office. For this form please visit http://www.state.ma.us/mepa.htm. In the case of a project that potentially may affect more than one municipality, the developer is required to consult with the Secretary of Environmental Affairs for guidance. While MEPA does conduct an on-site meeting and consultation session, it may or may not require a public hearing.[36]

4.2.3 Energy Facilities Siting Board

The EFSB will direct the applicant to:

- publish, prior to the hearing, notice of its proposed project in at least two newspapers of reasonable circulation
- mail a notice to owners of all property within a certain distance of proposed and alternative sites for the facility
- post notice of facility plans in the city or town halls of communities located in the vicinity of the proposed project

The public may examine a copy of the applicant's petition at the public library or clerk's office in the community where the facility is proposed, or at the EFSB office. The EFSB will set one or more public hearings in the city or town where the proposed facility is to be located. The developer will give an overview of the proposed facility, and public officials and the general public will have the opportunity to ask questions.[37]

4.3 Federal Permits and Approvals

In addition to state siting issues, there are several federal siting and permitting issue that renewable developers need to consider.

[36] MEPA homepage; http://www.state.ma.us/mepa/301-11tc.htm.
[37] "The Siting of Energy Facilities in the Commonwealth of Massachusetts." The Massachusetts Energy Facilities Siting Board, Boston MA; 1999.

4.3.1 National Environmental Policy Act (NEPA)

The National Environmental Policy Act (NEPA) was passed in 1970 to ensure that significant environmental impacts on or affecting federal lands or resources are taken into consideration before irretrievable commitments are made. The Council on Environmental Quality (CEQ) oversees NEPA.

The first step in the NEPA process is to screen the proposed action to determine the appropriate response for ensuring NEPA compliance. The applicant should consult with the CEQ as early as possible in the planning process to obtain guidance with respect to the appropriate scope of environmental information that will be needed to identify environmental factors and permitting requirements. Proposed actions fall into one of five categories:

- actions exempt from NEPA
- categorical exclusions
- actions covered by an existing NEPA environmental document
- actions that require preparation of an Environmental Assessment (EA) to determine if an Environmental Impact Statement (EIS) is needed
- actions that require preparation of an EIS

An EA is intended to be a concise public document that provides sufficient evidence and analysis for determining whether to order an EIS or a Finding of No Significant Impact (FONSI). EAs and FONSIs may be filed jointly. If the EA finds that a significant impact is likely, then a draft and final EIS must be prepared. Public comment periods must be included for EAs as well as for the draft and the final EIS. An EIS must be filed with the Environmental Protection Agency (EPA) and a notice must be published in the Federal Register.

4.3.2 U.S. Army Corps of Engineers (COE)

4.3.2.1 Section 10 Permit – Construction in Navigable Waters

The Army Corps of Engineers (COE), under the authority of Section 10 of the Rivers and Harbors Act of 1899, requires a permit for the construction of a structure and work under, in, or over any navigable waters of the United Sates. This permit applies to the construction of intake and discharge structures in such navigable waters and all ocean waters within a zone of 3 nautical miles from the coastline. A Section 10 permit is also needed for offshore wind or transmission lines in the water. It is expected that such structures may be required for a water supply intake and/or a wastewater discharge system. The homepage for the Corps of Engineers is http://www.usace.army.mil; the home page for the New England District office specifically may be found at http://www.nae.usace.army.mil.

4.3.2.2 Section 404 – Dredging or Filling

Section 404 of the Clean Water Act prohibits the discharge of dredged or fill materials into waters of the United States without a federal-level permit from the COE. Waters of the United States are broadly defined by the Clean Water Act to include wetlands, all oceanic waters within a zone of 3 nautical miles from the coastline, as well as other water bodies and waterways. COE jurisdiction includes all fill placed in a wetland.

Section 103 of the Marine Protection Research and Sanctuaries Act authorizes the Corps to regulate the transportation of dredged material for the purpose of disposal in the ocean.

4.3.2.3 U.S. EPA Veto Authority

The EPA retains the right to veto approval of a Section 404 permit if it determines that there will be a significant impact on a waterway or wetlands resource area. Only one such veto has been issued in Massachusetts to date.

4.3.2.4 Permit Application and Review

Application materials required for these permits include a description of the project, drawings detailing the location and extent of work proposed in wetlands and waterways, and a description of and plans for the mitigation proposed. Applications can be obtained from and submitted to:

United State Army Corps of Engineers
New England District Regulatory Branch
696 Virginia Road
Concord, MA 01742
1-800-362-4367
http://www.nae.usace.army.mil

The COE permit review process is based on a determination of compliance with the section 404 (b)(1) guidelines, and a determination that the project is not contrary to the public interest. Public notices are issued once a complete permit application has been filed. The COE reviews comments from the public notice and may request additional information from the applicant. A public hearing may then be held with a decision to follow. This process may take six months or more.

4.3.2.5 State Programmatic General Permits (PGP)

The COE's State Programmatic General Permits (PGP) have replaced nationwide General Permits in New England. There is a PGP in Massachusetts. The PGPs have three levels of review:

- Category I conditions and authorizes very minimal impact projects of minimal environmental impact without requiring reporting to the COE upon issuance of requisite state permits.
- Category II includes projects that have the potential to have more than minimal environmental impact and requires that applications be submitted to the COE for screening with State and federal resource agencies.
- Category III includes projects that are presumed to have environmental impacts and must therefore go through the Corps' Individual Permitting process.

The results of Category II screening are either: 1) a request for additional information; 2) project approval under the PGP; or 3) a determination that the project will have more than minimal adverse effects and must be reviewed under the Individual Permit process.

Ninety-five percent of all applications in New England are approved under a PGP in less than 30 days.[38] Copies of the PGP, or any other information regarding the Regulatory Program may be obtained by calling 1-800-362-4367 (in Massachusetts), or 1-800-343-4789 (in Maine, Vermont, New Hampshire, Connecticut, and Rhode Island).

4.3.3 U.S. EPA NPDES Permit

National Pollutant Discharge Elimination System (NPDES) permits, administered by the U.S. Environmental Protection Agency under section 402 of the Clean Water Act (CWA), are required for all point source discharges of pollutants into navigable waterways and their tributaries. Two sets of standards determine acceptable levels of discharge:

- Water quality-based standards are designed to protect receiving bodies of water from failing to meet acceptable water quality standards.
- Technology-based standards ensure that, regardless of the quality of the receiving water body, a type of discharge meets a minimum level of control.

Certain types of industrial discharges, such as those into sanitary sewer systems, may not require NPDES permits, but will be required to meet certain local standards, and may be subject to the Industrial Pretreatment Program.

The Industrial Pretreatment Program prevents the discharge of pollutants to a Publicly-Owned Treatment Work (POTW) which will interfere with the operation of the POTW or its use and disposal of municipal biosolids. In addition, the Pretreatment Program prevents the introduction of pollutants to POTWs that may pass through into rivers, lakes, and streams, causing increased toxicity or other impacts. Implementation of the Pretreatment Program is outlined in 40 CFR 403.

Discharges potentially regulated by NPDES fall into three categories:

- conventional pollutants, such as sanitary waste or gray water
- toxic pollutants, which are grouped into organics (including pesticides, solvents, PCBs, and dioxins) and metals (including lead, silver, mercury, copper, chromium, zinc, nickel, and cadmium)
- non-conventional pollutants, such as nitrogen, phosphorus, or any other substance that is not conventional or toxic

[38] Individual state reports can be found on the website at www.nae.usace.army.mil/pao/stuprpts.htm.

Regular monitoring and reporting are required under both the NPDES permit and the Pretreatment Program**.** Failure to meet the conditions of either may result in a range of enforcement actions. The U.S. EPA, authorized states, or citizens may bring suits for violations of the CWA under section 505 of the CWA. In addition to reviewing developers' data submittals, EPA may conduct on-site inspections as part of monitoring compliance status.

4.3.4 Federal Aviation Administration (FAA)

FAA regulations require that a notification form be filed for all structures potentially considered being obstructions to aircraft. FAA Notice of Proposed Construction is required for any proposed structure more than 200 feet above ground level. If a project is less than 20,000 feet from the nearest airport runway, more restrictive requirements apply. FAA review results in a determination of whether or not the proposed structure would be a hazard to air navigation, although no permit is issued. FAA also can require special markings or warning devices on a facility to ensure public aviation safety.

This information can be found at the FAA web site, http://www.faa.gov/ats/ata/ata400/7460-1f.doc, or by calling the Regional Air Traffic and Air Space Manager's office in Burlington, MA at 781-238-7520.

4.3.5 Federal Emergency Management Administration (FEMA)

FEMA has adopted regulations pursuant to the Flood Disaster Protection Act of 1973 that have resulted in identification of special flood hazard areas, those within the 100-year flood plain, as designated by FEMA. While FEMA does not conduct any specific pre-construction reviews for projects, those located in special flood hazard areas are subject to federal restrictions and requirements concerning loans and insurance.

Information on FEMA can be found on its web site, http://www.fema.gov, or by contacting the Region I office in Boston at 617-223-9540.

4.4 Local Permitting Issues

4.4.1 Solar Access Laws

The Massachusetts Solar Access Law (MGL c. 40A, ss. 1A, 3, 9B; MGL c 41, ss. 81Q) both allows for the creation of voluntary solar easements to protect solar exposure and authorizes zoning rules that prohibit unreasonable infringements on solar access. Similar to solar easement provisions in many other states, the Massachusetts solar easement allows for the voluntary creation of solar access contracts, but does not make solar access an automatic right. Massachusetts prohibits zoning regulations from unreasonably denying solar access. In addition, the statutes allow for communities to authorize zoning boards to issue permits creating solar rights.

"Solar access" is defined under Massachusetts law as "the access of a solar energy system to direct sunlight." Eligible solar technologies outlined in the Massachusetts Solar

Access Law include: passive solar heat; active solar water heat; active solar space heat; solar industrial process heat; solar thermal electricity; and photovoltaics. The law is applicable to commercial, industrial, and residential sectors.

Zoning ordinances or by-laws adopted by communities for their zoning boards to administer may protect solar access by regulating the orientation of streets, lots and buildings, creating maximum building height limits and/or minimum building set back requirements, instituting limitations on the type, height, and placement of vegetation, and other provisions. Zoning ordinances or by-laws may also establish buffer zones and additional districts that overlap existing zoning districts. Zoning ordinances or by-laws that protect solar access may also regulate the planting and trimming of vegetation on public property to protect the solar access of private and public solar energy systems and buildings. Solar energy systems may be exempted from restrictions for set back, building height, and lot coverage.

Communities in Massachusetts may also pass zoning ordinances or by-laws that provide for the issuance of special permits that protect access to direct sunlight for owners of solar energy systems. Where adopted, ordinances or by-laws may create an easement to sunlight over neighboring property. In doing so, they may also specify what constitutes an impermissible interference with the right to direct sunlight. Such ordinances or by-laws may define standards for issuing solar access permits that balance the need of solar energy systems for direct sunlight with the rights of neighboring property owners to the reasonable use of their property within other zoning restrictions. Ordinances or by-laws may also outline a process for notifying affected property owners and having a hearing and an appeals process. Zoning ordinances or by-laws may also provide for establishment of a solar map that identifies all the local properties burdened by or benefiting from solar access permits.

Prospective solar generators should check with their local communities to determine whether they have adopted zoning regulations to encourage solar access.[39]

4.4.2 Local Permits and Approvals

QFs and OSGFs may need to obtain a variety of local permits and approvals before building or operating their facilities. Most permits and approvals are similar to those various types that commercial facilities must obtain; some, however, may involve laws that are specific to the kind of facility being built. In some cases, community permits or approvals reflect policies that are unique to the town or city where they were established. It is very important that developers of QFs and OSGFs determine early in the process what laws their facilities will be subject to at the local level and the specific permits and approvals that will need to be obtained.

In Massachusetts, local approvals for QFs and OSGFs may involve the following:

[39] Based on conversations with the New England Solar Energy Association, the North East Sustainable Energy Association, and the Boston Area Solar Energy Association, we did not identify any municipalities that had adopted Solar Access Laws.

- zoning and/or site plan review (including setback, height, and other requirements, including any solar access issues)
- building permits (including for improvements such as non-removable PV roofs or curtain wall products)
- construction in or near wetlands or floodplains, and orders of conditions from conservation commissions
- sewer connection and pre-treatment
- water quality and supply issues.

State building codes, including electrical and plumbing codes, are enforced at the community level by the local building, electric, gas, and plumbing inspectors (in some cases within a Division of Inspectional Services). While often drawing in part from national model codes, the Commonwealth of Massachusetts has developed its own set of codes that are administered by local officials.

Some of the local officials or departments that should be contacted at the early stages of a project are listed in Table 8.

Table 8: Local Siting and Permitting Issues

Authority	Examples of Issues
Building inspector	Building permits Massachusetts Building Code Local zoning laws Oil tank storage approval Solar access laws (if locally adopted)
(Zoning) Board of Appeals	Variances, special permits, review of building inspector determinations, solar access permits (if locally adopted)
Electrical inspector	Massachusetts electrical code
Plumbing inspector	Plumbing provisions of Massachusetts fuel, gas & plumbing code
Gas inspector	Gas provisions of Massachusetts fuel, gas & plumbing code
Mayor/City Manager/City Council Board of Selectmen/ Town Manager/Town Meeting	Main decision-makers (City) Main decision-makers (Town)
Planning Board	Site plan approval (Board of Selectmen in some towns)
Conservation Commission	Wetlands issues Floodplains issues Soil erosion and runoff issues
Water/Sewer Commission	Protection & adequacy of local water supply and quality of water Sewer extensions/connections
Fire Inspector	Oil tank storage approval Storage of ammonia
Historical Commission	Modifications to site or structure with historical significance
Department of Public Works	Curb cuts/service roads
Town/City Engineer	Grading/highway/traffic issues
Board of Public Health	Public health issues (including air quality, hazardous waste, etc.)

Some local issues will be relevant for a variety of types of QF projects. Requirements regarding setback of structures and their relationship to property lines and public roads, height limitations, erosion and sedimentation control issues, air and water quality matters, noise levels, traffic patterns, building upon historic/culturally significant or scenic vista locations, signage, etc., may be applicable to a variety of different types of small generation plants. On the other hand, certain types of generation may involve unique issues (e.g., possible broadcast signal interference issues for wind power).

Local requirements and local permitting may vary considerably. Because a detailed discussion of local permits and licenses goes beyond the scope of this Guidebook, it is very important that a developer of a QF or OSGF contact local authorities early in the project's development to make sure that all local issues are addressed.

In addition to contacting the agencies or officials listed above, it is also advisable for a developer of a QF or OSGF to contact abutters to a project as early as possible. Abutters will be particularly interested in the impact of a project on their property values, visual effects, anticipated noise levels, any anticipated change in traffic patterns, and the project's overall impact on the neighborhood.

It may be best to contact local agencies and abutters in the pre-application phase, before a QF or OSGF officially files an application for a permit. This ensures that the QF or OSGF developer has adequate opportunity to address relevant issues before finalizing its proposal. Depending on the scope of the project, a QF developer may want to encourage public meetings or other forms of community outreach to share information, exchange views, and clear up any potential misunderstandings.

A QF or OSGF may have implications for local property taxes. A community's Board of Assessors would be involved in these issues. Some projects, such as solar or wind power systems, may be eligible for a local property tax exemption. Tax exemptions and other types of incentives for renewable energy and distributed generation are more fully discussed in Section 6.0 of this Guidebook.

5.0 Distribution and Transmission Interconnection and Metering Issues

In order to sell power to others, a Qualifying Facility (QF) or an on-site generating facility (OSGF) must interconnect, or hook up its generating facility with the grid. An OSGF will sell its excess power---once its own needs are met---back to the distribution company so that the power can be sold in the wholesale market. A small QF is also likely to have the distribution company sell its power in the wholesale market. A large QF, on the other hand, may sell its power directly itself.

All QFs and OSGFs must link their power with the grid. With the exception of very large generators able to link directly to the transmission system, QFs and OSGFs must first interconnect at the distribution level. Key safety procedures must be followed in performing this interconnection. Arrangements must be made to have a facility's output flow through New England's transmission system, operated by the Independent System Operator (ISO) New England. The distribution company will generally perform this service for OSGFs and small QFs. Large QFs, on the other hand, will likely need to establish their own arrangements directly with the ISO and the transmission system. QFs and OSGFs will require metering which monitors their output.

5.1 Interconnection with the Distribution Company

A generator of electricity seeking to sell some or all of its electricity needs to interconnect its facility with the electric grid. This would be true both for an OSGF that is ultimately intending to sell its excess electricity through net metering to the distribution company, or a QF that is intending to sell its output to the distribution company for sale to the ISO power exchange. Unless it is a very large generator with a sizeable transformer that can directly link its power to the transmission system, a generator of electricity will first interconnect with the distribution system of the local distribution company that is responsible for distributing power to retail customers.

An interconnection affects not only the generator but also the grid as well. Therefore, a variety of contractual and technical issues arise with regard to interconnection. Regulations promulgated by the Massachusetts Department of Telecommunications and Energy (DTE) set standards and principles regarding interconnection and metering.[40] However, each distribution company has its own set of written procedures with regard to interconnection that it files with the DTE,[41] as well as its own forms. A QF or OSGF owner should contact its local distribution company and obtain these documents.

Essential technical requirements must be met to prevent backfeeding of power from the QF or OSGF to the distribution company system during power outages, and for the QF or OSGF to match the distribution company system's requirements regarding voltage,

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[40]220 CMR 7.00 et seq. DTE promulgated these regulations regarding sales of electricity between QFs and OSGFs and the distribution companies on December 27, 1999.

[41]DTE required each distribution company to file written procedures concerning interconnection and metering with DTE within 60 days of the regulations' effective date.

frequency, distortion, and harmonics. Many of these technical issues associated with interconnection involve matters related to human and equipment safety, system reliability, and power quality.

Other precautions relate to specific types of generation. The generation of power from PV, wind, and fuel cells usually involves the production of direct-current (DC) power. This DC power needs to be inverted to alternating-current (AC) power. Grid-tied inverters perform this function and also generally have built-in safety features to protect against islanding, a potentially dangerous situation in which the generator remains energized and connected even after the main system goes down. This is prevented by the inverter's safety features which monitor the frequency and voltage of the distribution company line, and shut off the local generator when the distribution company's power goes down or varies significantly from its normal frequency and voltage ranges. The goal is to prevent potentially hazardous situations for the general population and for distribution company service personnel working on the grid. Another goal is to prevent potential damage to customers' electrical equipment. The distribution company may also require a supplementary clearly marked manual disconnect switch external to a building to provide another means of dealing with islanding.

Some small hydro facilities may not have inverters. Instead, they are likely to require additional protective equipment that the distribution company will specify. Microturbines may or may not have inverter technology.

In addition to safety, power quality must be protected in any interconnection. Power is routinely supplied at a particular voltage and frequency. If there is deviation in the voltage or frequency, appliances can malfunction or become damaged. Other power quality issues that need to be addressed involve harmonics, power factor, DC injection, and voltage flicker.

Under the DTE's regulations, certain standards and principles are established for interconnection. The first step involves an inspection by the distribution company to determine the costs of interconnection.

5.1.1 Inspection

Under DTE's regulations, at the request of a QF or an OSGF, a distribution company within 45 days will perform an initial site inspection at no charge to evaluate the equipment needed to interconnect in a manner that protects the distribution company's system. This inspection is also meant to estimate the costs of interconnection.

5.1.2 Cost Estimate

If a thorough estimate of the costs of interconnection cannot be determined after the initial site inspection, upon request of a QF or an OSGF, the distribution company will perform a more complete estimate, including engineering studies where needed. The QF or OSGF will pay for the costs of this more complete estimate. Costs of studies vary, depending on the size of the QF or OSGF. Facilities with projected output of over 60 kW are among those facilities likely to need engineering studies. Each distribution company is required to develop written procedures for estimating interconnection costs. If the parties cannot agree on interconnection costs or procedures, they may petition the DTE to review the reasonableness of the distribution company's estimate.

5.1.3 Standards and Safety Requirements for Interconnection

After the onset of restructuring in Massachusetts, DTE enacted regulations that required each distribution company to file with the DTE non-discriminatory interconnection standards for the connection of generation facilities to distribution facilities 220 CMR 11.04 (4). These segments are meant to ensure that all facilities have fair access on reasonable terms to the distribution company's system.

In late 1999, DTE enacted further regulations for the interconnection of QFs and OSGFs 220 CMR, 7.00 et seq. Included is a provision clarifying the standards for interconnections meant to protect against the inadvertent and unwanted re-energizing of a distribution company's dead line or bus; interconnection while out of synchronization; ground and phase faults; frequency outside permissible limits; and voltage that is generated outside permissible limits.

A number of national codes and safety organizations offer guidelines regarding the installation of safe equipment. Among them is the National Fire Protection Association (NFPA), which publishes the National Electric Code (NEC) for electrical equipment and wiring safety in buildings. Article 690 covers photovoltaic systems. Massachusetts has adopted the NEC Code.

The Institute of Electrical and Electronics Engineers (IEEE) issues recommended practices for utility equipment with regard to safety, power quality, and equipment protection. IEEE Standard (STD) 929-2000 covers utility interface of photovoltaic systems. A proposed standard, IEEE P1547, is meant to cover the interconnection of all small-distributed generation. The Underwriters Laboratories (UL) Standard 1741 governs inverters for PV systems covered by IEEE STD 929-2000 and their testing procedures. For more information on how to obtain IEEE Standards, please visit http://standards.ieee.org/catalog/olis/index.html.

Under DTE's regulations, a QF or OSGF must provide the distribution company with written certification from qualified personnel or a qualified testing agency certifying that protective devices and related equipment have been installed and successfully tested before they can deliver their power to the distribution company. The distribution company has the right at any time to inspect and test (at no charge to the customer) the electrical interface to ensure that it is working properly.

5.1.4 Procedures for Interconnection

DTE's regulations provide that a QF or OSGF must notify the distribution company in writing if it wishes to interconnect with the distribution company's system. The distribution company must then interconnect the QF or OSGF within 90 days. If extensive changes must be made to the distribution company's transmission or distribution system, the distribution company may seek additional time from DTE. DTE also has the power to order a distribution company to interconnect a QF or OSGF in a timely manner, in the event that a QF or OSGF petitions the DTE for review of its case.

> Under DTE's regulations, a QF or OSGF shall file a written notice of intent to interconnect that:
>
> - identifies the site
> - describes the type of facility (including whether it is a small power production facility or a cogeneration facility),and its type of energy source
> - provides the power production capacity of the facility and the maximum net energy that may be delivered to the distribution company's system
> - identifies the owners of the facility
> - estimates the likely date of installation and the anticipated on-line date
> - specifies the anticipated method of purchase and sale of power with the distribution company (simultaneous purchase and sale, net purchase and sale, net metering, or some other method)
> - describes the power conditioning equipment
> - identifies the type of generator to be used in the facility.

5.1.5 Costs of Interconnection

DTE's regulations provide that it is the responsibility of the QF or OSGF to pay for the costs of interconnection of its facility with the distribution company's system. In practical terms, this means reimbursing the distribution company for the incremental costs that are incurred as a result of interconnecting the facility, including any meter installation. These costs include installation costs, operations and maintenance expenses, property taxes, and any changes to the distribution and transmission system that are for the sole benefit of the QF or OSGF.

On the other hand, costs associated with the QF's or OSGF's purchase of electricity from the distribution company are not to be considered interconnection costs. If the QF or OSGF will be buying electricity from the distribution company under a standard rate tariff or special contract that includes customer interconnection costs, these costs will be deducted to calculate the incremental costs for interconnection that are owed by the QF or OSGF for bringing its generation into the distribution company's system.

Under DTE's regulations, a QF may, at its option, amortize interconnection costs over a period of up to three years. The QF may choose the specific period of amortization. In addition to recouping the actual costs of interconnection, a distribution company receives interest on these costs, computed at the distribution company's average weighted cost of capital.

DTE regulations provide for standard charges, set out in an approved tariff filed by the distribution company, for interconnection equipment, meters, and meter reading costs. Where standard charges are not applicable, they are to be based on the distribution company's invoice cost for the equipment. Interconnection costs that are not standardized or invoiced are to be estimated on a case-by-case basis. In certain cases certain exit fees may also be charged, but many QFs and OSGFs are likely to be exempted from these exit fees (see section 5.1.7 below).

5.1.6 Metering

Under DTE's regulations, the QF or OSGF is required to furnish and install the necessary meter socket and wiring pursuant to accepted electrical standards. The distribution company is required to furnish, read, and maintain the metering equipment.

A second meter may be installed to measure the output of the on-site generation, or a single meter may be installed that under net metering works in both directions (allowing generation output to offset electricity usage).

If the QF or OSGF decides to own the meter, it must pay a monthly charge to the distribution company for meter maintenance as well as incremental reading and billing costs. If the QF or OSGF chooses to have the distribution company own the meter, the QF's or OSGF's monthly charge will cover meter maintenance and incremental reading and billing costs, as well as taxes, the distribution company's allowable return on the invoice cost of the meter, and depreciation.

If a QF is 1 MW or greater in its design capacity, the QF must use bi-directional, interval recording metering with the capability for remote access. The remote access capability may involve telemetering to the extent that standards of the New England Power Pool (NEPOOL) require it. The metering must also be in compliance with NEPOOL's standards overall. The interval recording metering will be controlled, tested, maintained, and read by the distribution company.

If a QF's design capacity is greater than 60 kW but less than 1 MW, or is less than 60 kW but is not involved in net metering, the QF's metering system must be able to record sales to the distribution company.

If the QF or OSGF has a design capacity of less than 60 kW, its owners have the option of net metering, which requires a standard service meter capable of running backwards.

5.1.7 Exit Charges

In some cases, on behalf of its other customers, a distribution company is allowed to charge exit fees to customers that develop on-site generation because of the impact that their leaving has on the distribution company's overall revenues, and in turn the regulated rates of its other customers. However, Massachusetts's restructuring law specifically provides that distribution companies cannot charge exit fees to renewable or distributed generation facilities if certain conditions are met. If a customer provides the distribution company and DTE with at least six months notice of its plans to install on-site cogeneration equipment, renewable energy technologies, or fuel cells, it will not be subject to an exit charge. For facilities that are eligible for net metering---for example, facilities with a design capacity of 60 kW or less---no such six-month notice is even required.[42]

In addition, if a customer provides the distribution company and DTE with at least six months notice of its plans to buy electricity from onsite renewable energy technologies, fuel cells, or cogeneration equipment with a combined heat and power system efficiency of at least 50 percent, or if the customer operates or buys from an on site generation or cogeneration facility of 60 kW or less that is eligible for net metering, it will not be subject to an exit charge even though its actions will result in less electricity being purchased from the service provider. In both cases, certain additional conditions also need to be met regarding the total amount of generation leaving the system.[43]

However, if the DTE determines that such actions will have a significant adverse impact on the electric bills of the distribution company's other customers during the time the distribution company is trying to recover its transition costs, the DTE may order that an exit charge be paid. Each year, the DTE is to prepare a report concerning this issue.

5.1.8 Other Issues

Distribution companies are prohibited under DTE regulations from charging net metering customers special fees (such as backup charges and demand charges) that they do not charge other distribution service customers.[44] They also cannot require that net metering customers carry liability insurance as long as their facility meets the distribution company's interconnection standards and all relevant safety and power quality standards.

5.2 Interconnection with ISO New England

Developers of large-scale QFs need to interconnect their generation with the transmission system via the ISO. OSGFs and small-scale QFs, because of their size, will generally deal more directly with the local distribution company. The local distribution company, or another NEPOOL participant, will then handle the sale of their power to the generating pool overseen by the ISO.

QFs producing less than 1 MW of power generally will need to have the sale of their

[42] 220 CMR 11.03(4)(d).
[43] The QF or OSGF cannot have been responsible for more than 10% of the service provider's annual gross revenues during the past year; and the combined previous electricity purchases of the QF or OSGF and all other customers who, during a three-year period leave the service provider's system, cannot total 10 % or more of the service provider's annual gross revenues. If they total more than 10%, each such customer will pay an exit charge that reflects its pro rata share of the portion of annual gross revenues that is over the 10% limit. The DTE publishes a report every July 1st indicating the amount of generation produced from QFs and OSGFs so that each utility can keep track of the growth in the % revenue each year.
[44] 220 C.M.R. 11.04 (7)(c).

power handled by their distribution company. Because of their small size, they are not allowed to register their assets directly with the ISO but must have either their distribution company or their competitive supplier register their assets. A QF should inquire ahead of time whether and to what extent it may be assessed a charge for this service. Since a small QF may not have revenue quality metering, is not centrally dispatched, and needs to be a customer of a NEPOOL participant to have its power sold in the ISO's generating pool, it likely will need to rely on the distribution company to handle the sale of its power. Likewise, an OSGF, which by definition produces less than 60 kW, will most likely use net metering to sell its power to the distribution company.

QFs larger than 1 MW but smaller than 5 MW are also likely to have the sale of their power handled by their distribution company. On the other hand, QFs larger than 5 MW may explore NEPOOL participation to interconnect directly with the system in order to sell their power directly into the wholesale marketplace.

Facilities producing less than 5 MW will generally find the costs of interconnection to the NEPOOL system too high. In order to be fully market-enabled, these facilities must be dispatchable, and able to receive and respond to dispatch instructions from the ISO. In order to do this, they must have personnel on-duty for all hours in which they are generating. This would involve significant costs for small-scale generators, and could even be an issue for some generators with over 5 MW capacity.

Whatever a QF's size, however, at the time of interconnecting with its distribution company, a QF should determine what its intended role in the wholesale system will be, and how to structure its wholesale arrangements.

If the project will be interconnected with the NEPOOL transmission system via the ISO, the developer must have a System Impact Study (SIS) performed, at the developer's cost. The ISO staff oversees performance of the study. The study is meant to determine whether the generating facility could have its power transmitted without hurting either the reliability or operating characteristics of the rest of the transmission system. New England's bulk power system is a network that has physical capacity limits due to thermal, stability, and voltage considerations. The SIS evaluates whether there would be an impact on the transmission system---whether locally or hundreds of miles away---if the new generating facility were to come on line.

The SIS is meant specifically to:

- evaluate the impact the proposed generation would have on the local transmission provider's system, as well as on the regional system
- determine specific modifications in the transmission lines, terminal equipment, protection, and control systems that will be needed to incorporate the new generation into the system. These pertain both to the local interconnection requirements and upgrades to the power system
- offer a cost estimate for the transmission upgrades and additions to the system (if required)

The SIS is meant to ensure that the generating unit will meet the Minimum Interconnection Standard that is defined in Section 49 of the NEPOOL Tariff. For a Scope of Study for the SIS visit www.iso-ne.com.

If the new facility is found likely to have an adverse impact on the rest of the system, the developer might agree to certain conditions regarding the sale and generation of its power. Otherwise, or alternatively, upgrades to the transmission system might be required to accommodate this new power. More and more, ISOs are developing congestion management systems in which those who cause the transmission congestion are assessed congestion "rents".

A QF developer seeking an SIS should follow the latest "Procedures for the Establishment and Study of NEPOOL Interconnection" (which are updated periodically). A copy of the procedures for such a study, as well as an application for a NEPOOL Interconnection System Impact Study (SIS), may be obtained from the ISO at its web site, www.iso-ne.com. There is a $500 application administration fee.

In its SIS application, an applicant seeking generation interconnection with the NEPOOL System via the ISO must demonstrate that it owns, leases, or has an option or contract on the site at which the facility is to be constructed and that it maintains control over the site. The applicant should also include a map of the project area that identifies the project location. In its application, the applicant is also asked to elect the basis by which the interconnection system impact study should be performed.

Within one business day after receiving the application, the ISO will notify the likely interconnecting Transmission Provider(s) that an application has been filed. The ISO has 30 days within which to tender an SIS Agreement to the generator, which then has 15 days from receipt of the agreement to sign and return it to the ISO. The SIS Agreement will state the estimated period of time needed to complete the SIS.

The SIS is then performed under the oversight of the ISO staff, which coordinates, reviews, and provides technical input into the study. The SIS is meant to identify physical interconnection requirements as well as to facilitate compliance with other NEPOOL requirements. The ISO and all potentially affected Transmission Providers are meant to play a role in the SIS. If more time or funds are needed to perform the study than originally anticipated, the ISO will notify the applicant. Throughout the study the applicant is to receive updates on the study's progress. A draft report is sent to the applicant for comment; all such comment must be received back within 15 days. Within 30 days thereafter if comments are received, or within two business days if no comments are received, the final report will be issued.

If the SIS report indicates that any transmission system modifications are needed, a Facilities Study may need to be performed. The first step would involve completion of a Facilities Study Agreement, or an Interim Facilities Study Agreement, within 30 days of submission of the final SIS report to the applicant.

If transmission system modifications are necessary, within 45 days of submission of the final SIS report to the applicant, the applicant and the Transmission Provider(s) may alternatively agree to an "Expedited Interconnection." The Transmission Provider(s) or others responsible for constructing the new facility or upgrades give the applicant a non-binding estimate of the new facility costs and other potential charges, which the applicant agrees, in writing, to pay.

Within 90 days after either the final Facilities Study report is completed, or an agreement for Expedited Interconnection has been signed, the applicant and the interconnecting Transmission Provider(s) will establish appropriate interconnection agreements, and the applicant will provide the required security.

A generator may agree to pay for a transmission upgrade. Alternatively, a generator may change its original plans in order to enable its facility to provide power to the system without needing a transmission upgrade.

If the SIS report indicates that no transmission system modifications are necessary, a Facilities Study may not be required. The applicant and interconnecting Transmission Provider(s) will then establish appropriate interconnection agreements, with the applicant providing required security, within 90 days after the final SIS report is issued.

All interconnections and all transmission modifications must meet the requirements of Section 17.4 of the Restated NEPOOL Agreement review and approval process. The scope and cost of the projected transmission modifications may change significantly from those suggested in the SIS and Facilities Study.

If a QF involves 100 MW or more in net output, or will involve certain transmission facility changes or certain interconnections with non-NEPOOL utilities, the developer will also need to submit an application to NEPOOL under Section 10.4 of the NEPOOL Agreement: Criteria, Rules and Standards No. 39.[45]

It is important for an applicant to submit an application to NEPOOL as soon as possible. This will help to ensure that it gains priority with regard to the use of limited remaining transmission capability in the event that another project turns out also to need this capability. NEPOOL processes applications on a first-come-first-served basis except for the subordinate 17.4 application process (this policy is discussed below). Therefore, applicants need to make sure they follow the various procedures and meet the various deadlines in order to make sure that they maintain their place in line.

There may be instances, however, in which a developer is ready to proceed with construction of its project before other projects that are ahead of the developer in the SIS queue are ready. For such situations, NEPOOL has developed a Subordinate 17.4 Application Policy that sets out an optional process that project developers may choose.

[45] Section 1.1.1, Appendix I, "Requirements, Procedures, and forms for Submitting 10.4 Applications." Criteria, Rules, and Standards No. 39. NEPOOL Executive Committee. Revised November 5, 1993.

The above discussion focuses on a project's impact on the major transmission lines, known as pool transmission facilities (PTFs). If purchasing power from a generator is connected directly to the PTF, end-users pay standard transmission charges on their bills arising from the NEPOOL Open Access Transmission Tariff. If a project is sited off the PTF, however, it will need an agreement with the local network provider for this type of interconnection based on Federal Energy Regulatory Commission-approved tariffs that vary for each local network provider. In analyzing the economics of building a facility and selling to the spot market, a renewable energy and/or distributed generation developer needs to factor in any such local network charges.

6.0 Federal and State Programs, Financial Incentives, and Policies That Support Renewable and Distributed Generation

There are a number of federal and state programs, policies, and financial incentives, such as tax credits and rebates, that support the development of renewable and distributed generation. In addition, federal and state agencies offer grants, financing resources, such as access to loan programs, and other financial incentives for renewable and distributed generation projects. Some of these resources are summarized below. This summary is not intended to replace consultations with a lawyer, tax preparer, or with government agencies, who can provide a more thorough explanation of incentives and their availability.

6.1 Federal and State Grant and Loan Resources

Federal, independent, and state grants and loans are available to renewable energy developers. The federal government, principally through the U.S. Department of Energy (DOE), offers grants for renewable energy projects. In addition, loans may be offered by banks or other lending institutions in conjunction with federal or industry initiatives. The Massachusetts Renewable Energy Trust Fund may also provide grants and loans to support renewable energy.

6.1.1 Federal and Independent Grant and Loan Resources

6.1.1.1 Million Solar Roofs Small Grants Program for State and Community Partnerships

The DOE is making $600,000 available to state and community partnerships involved in the Million Solar Roofs Initiative. Note that these grants are not available to individual home or business owners.

To become a Million Solar Roofs State and Community Partnership, any state or municipality, on behalf of a specific partnership, must send a letter to the Million Solar Roofs Coordinator. The letter must:

- express the organization's commitment to the initiative's objectives
- describe the general nature of the partnership and its membership
- indicate its goal for the specific number of qualified solar energy systems to be installed on buildings within a specific community. At a minimum, partnerships must commit to installing 500 solar energy systems by 2010. In addition, a Partnership is asked to develop a draft plan for meeting its goals

In return for this commitment, the DOE, through its network of Regional Support Offices, will coordinate and provide support for the partnerships. Benefits include access to the Million Solar Roofs Small Grants program, and assistance in accessing low-cost loans, buy-down grants, and other financial assistance.

For more information visit http://www.eren.doe.gov/millionroofs/comm.html.

6.1.1.2 The Utility PhotoVoltaic Group (UPVG)

The Utility PhotoVoltaic Group (UPVG) is an association of U.S. and international utilities and power producers formed in 1992 to accelerate the use of cost-effective off-grid and emerging grid-connected applications of solar electricity (photovoltaics) for the benefit of utilities and their customers. The UPVG is the largest coalition of electric utilities actively working to expand photovoltaics worldwide. The UPVG receives support from the U.S. Department of Energy.

The nonprofit association receives funding from the U.S. Department of Energy to manage TEAM-UP (Technology Experience to Accelerate Markets in Utility Photovoltaics), a program to fund practical photovoltaics applications. TEAM-UP is helping to create an expanded market for solar electricity. TEAM-UP awards cost-sharing dollars on a competitive basis.[46]

Visit http://www.upvg.org/upvg/index.htm for more information.

Utility PhotoVoltaic Group
1800 M Street, N.W., Suite 300
Washington, DC 20036-5802, U.S.A.
Phone (202) 857-0898
Fax (202) 223-5537

6.1.1.3 National Industrial Competitiveness through Energy, Environment, and Economics Grant

The U.S. Department of Energy (DOE) sponsors an innovative, cost-sharing program to promote energy efficiency, clean production, and economic competitiveness in industry. The grant program, known as the National Industrial Competitiveness Through Energy, Environment, and Economics (NICE3), provides funding to state and industry partnerships (large and small business) for projects that develop and demonstrate advances in energy efficiency and clean production technologies.

Industry applicants must submit project proposals through a state energy, pollution prevention, or business development office. State and Industry partnerships are eligible to receive a one-time grant of up to $525,000. The industrial partner may receive a maximum of $500,000 in federal funding. Non-federal cost share must be at least 50% of the total cost of the project.

For more information visit http://www.oit.doe.gov/nice3/grants/grants.shtml.

6.1.1.4 Federal Energy Management Program

Consistent with EPAct and Executive Order 12902, the DOE's Federal Energy

[46] http://www.upvg.org/upvg/index.htm.

Management Program (FEMP) has increased its efforts to use solar energy systems in federal facilities. Federal agencies contract with energy service companies, which finance all the up-front costs (identifying building energy requirements and acquiring, installing, operating, and maintaining the energy equipment) with Energy Savings Performance Contracts (ESPCs) as governed by 10 CFR 436 Subpart B. In exchange, the contractor receives a share of the cost savings resulting from these improvements until the contract period expires, which can be up to 25 years. This alternative finance mechanism uses private sector funds to achieve federal goals to reduce fossil fuel energy consumption at no capital cost to the federal government.

The opportunity also exists to bundle technologies with short payback periods (energy conservation measures) with technologies with long payback periods (photovoltaic). Photovoltaic has proven cost effective in remote applications, such as national forests, and currently FEMP is seeking opportunities to install grid-connected photovoltaic systems with ESPCs. In addition, Super ESPCs are currently under development. Super ESPCs will be technology-specific and will streamline the process of an agency acquiring photovoltaic and solar thermal systems with a simple delivery order. For more information visit the Federal Energy Management web site at http://www.eren.doe.gov/femp/financing/espc_intro.html.

6.1.1.5 U.S. Environmental Protection Agency (EPA) Environmental Finance Program

The EPA's Environmental Finance Program (EFP) includes:

- 1) the Environmental Financing Information Network (EFIN), which provides an outreach service with electronic access to many types of environmental financing information on financing alternatives for state and local environmental programs and projects (EFIN services include a World Wide Web site, on-line database, referrals to an expert contact network, an infoline, and distribution of EFP and EPA publications)
- the Environmental Finance Center Network (EFCN), a university-based program providing financial outreach services to communities. The Network consists of six Environmental Finance Centers that share information and expertise on finance issues and engage jointly in projects.

For more information visit http://www.epa.gov/efinpage.efin.htm.

6.1.1.6 U.S. Small Business Association (SBA)

The U.S. Small Business Administration (SBA) operates a loan fund to assist small businesses engaged in energy technology and efficiency projects. The SBA rarely makes a direct loan to applicants. Instead, it will work with a designated financial institution to guarantee such loans if certain requirements are met. Generally, loan guarantees cannot exceed $750,000 or 75% of the loan amount, whichever is less. For loans up to $100,000, the guaranteed amount cannot exceed 80% of the project.

The SBA also has a program that extends short-term financing to businesses that need assistance. The new program, called "CAPLines," was implemented to provide federally guaranteed revolving lines of credit to small businesses. To qualify for the program, the company needs to have assets adequate to secure the line of credit.

Approved renewable energy technologies that are eligible for SBA loans and loan guarantees include solar thermal and electric systems (photovoltaics), energy-efficient products and services, biofuels, industrial cogeneration, hydroelectric power, and wind energy. The loans may be used for a wide range of business investments, such as the purchase of machinery, equipment, furniture, fixtures, facilities, buildings, and supplies or materials. The acquisition of vacant land for construction of a plant may also be financed if the plant will be using energy-saving measures. Loan funds, not to exceed 30% of the total loan amount, may be used for research and development projects that follow certain guidelines.

For more information visit http://www.eren.doe.gov/consumerinfo/refbriefs/l113.html.

U.S. Small Business Administration
Office of Business Initiatives
409 3rd Street, SW
Washington, DC 20416
Phone: (800) 827-5722 or (202) 606-4000 (Washington, DC Region)
Fax: (202) 205-7024

6.1.1.7 Federal National Mortgage Association (Fannie Mae)

Using authority granted by 12 USC 171, Fannie Mae provides the Residential Energy Efficiency Improvement Loan. Fannie Mae is partnering with distribution companies to provide low interest unsecured consumer loans to distribution company customers for the installation of residential energy-efficient improvements. Solar hot water heaters and photovoltaic power systems are eligible technologies for this loan program. Compared to other unsecured consumer loans, this Residential Energy Efficiency Improvement Loan program provides a below-market interest rate.

For more information visit Fannie Mae at http://www.fanniemae.com.

6.1.1.8 Community Development Block Grant Program

The U.S. Department of Housing and Urban Development (HUD) Community Development Block Grant Program provides grants for the development of alternative and renewable energy sources. Eligible activities may include the acquisition, construction, reconstruction, or installation of power generation and distribution facilities using renewable energy systems. Qualified local governments (population over 50,000) may distribute this money through a grant, loan, or subsidy program for property rehabilitation projects (e.g., fund neighborhood based nonprofit organizations, local development corporations, or entities organized to carry out a neighborhood revitalization or community economic development projects), or public works (e.g. public lighting).

A current example of the HUD Block Grant Program supporting photovoltaic is the FIRST Low-Income Town Home Project in Philadelphia. This is a city-sponsored home-ownership program for low-income families. FIRST, a modular home manufacturer, is supplying 18 energy efficient town homes, each with a 1.44 kW integrated photovoltaic power system. For more information visit HUD at http://www.hud.gov/index.html.

6.1.1.9 Solar Energy Industries Association (SEIA) Solar Finance Program

The Solar Energy Industries Association (SEIA), in conjunction with Volt VIEWtech, a financial service provider, has developed the Solar Finance program. Solar Finance is a consumer finance-type loan program for residential solar water heating, pool heating, and photovoltaic systems. The program is available exclusively to national or state chapter SEIA members. Members may participate for a $500 annual fee, which SEIA uses to support marketing and promotional programs.

Solar Finance loans are available in amounts ranging from $2,500 to $25,000 with 5,7,10, or 15 years to pay based on loan amount. The fixed rate is approximately 13.9%, and there is no down payment. Solar Finance offers same day approvals.

For more information contact:

Solar Energy Industries Association
1111 North 19th Street; Suite 260
Arlington, VA 22209
Phone (703) 248 -0702
Fax (703) 248-0714
http://www.seia.org/solarfin.htm

6.1.2 Massachusetts Grant and Loan Resources

In Massachusetts, the primary source of funding of grants for renewable and distributed generation will be the Renewable Energy Trust Fund.

6.1.2.1 The Massachusetts Renewable Energy Trust Fund

As required by Massachusetts's restructuring law, since March 1, 1998 electricity customers (except municipal light department customers not participating in the competitive market) have been paying a system benefits charge to support the Renewable Energy Trust Fund. Administered by the Massachusetts Technology Park Corporation (MTPC),[47] the mission of the Renewable Energy Trust Fund is to:

- increase the use and generation of renewable energy in the state and region

[47] The Massachusetts Technology Park Corporation (MTPC) is an economic development organization established by the state to foster sustainable economic growth by promoting a better understanding of the forces that shape the state's economy, and by enabling greater collaboration among the diverse enterprises involved.

- enable Massachusetts companies to capture a greater share of the market for renewable energy technologies

The system benefits charge was projected to generate approximately $17 million in 1998, $30 million in 1999, $40 million in 2000, $30 million in 2001, and $20 million in 2002 and each year thereafter to support the Renewable Energy Initiative.[48] In addition, approximately $50 million from the fund will go to waste-to-energy facilities through 2002. The funds for waste-to-energy will be administered separately from the Massachusetts Renewable Energy Initiative.

The Massachusetts Renewable Energy Initiative may support technologies identified by Massachusetts's restructuring law, including:

- solar photovoltaic and solar thermal electric
- wind
- ocean thermal
- wave or tidal
- fuel cells
- hydroelectric power from naturally flowing and impounded water
- landfill gas
- waste-to-energy that is a component of conventional municipal solid waste plant technology in commercial use
- low emission, advanced biomass power conversion technologies
- storage and conversion technologies connected to certain generation projects.

Funds may also be used for appropriate joint energy efficiency and renewable projects, as well as for investments by distribution companies in renewable energy and distributed generation opportunities.

A municipality or group of municipalities establishing a load aggregation program and not served by a municipal light department can develop an energy plan to implement a demand side management program and renewable energy program. If the plan is certified by DTE, the municipality or group of municipalities may apply to the MTPC for funding.

Fund allocations will be determined by a Board of Directors that is composed of experts from the energy and technology industries, as well as prominent economic development officials. The Board may use the fund, for example, to provide grants, contracts, loans, equity investments, energy production credits, bill credits, or rebates to customers, financial or debt service obligation assistance, etc., to renewable energy projects and customers.

The MTPC is currently in the process of finalizing its strategic plan for the design, implementation, evaluation, and assessment of the Renewable Energy Trust Fund. There is,

[48] Massachusetts Technology Collaborative Renewable Energy Trust Fund Direction Statement. www.mtpc.org/renew/statement.htm.

however, an outstanding lawsuit that challenges its funding mechanism. Until this legal issue is resolved, the Renewable Energy Trust Fund will not ramp up to full operation.

For more information contact the MTPC at (508) 870-0312 or visit http://www.mtpc.org.

6.2 Federal Financial Incentives[49]

EPAct and the Internal Revenue Code include several measures to encourage investment in renewable and distributed generation by public and private entities. These measures include:

- Federal 10 Percent Investment Tax Credit for commercial purchases of solar property
- Federal Renewable Energy Production Tax Credit of 1.5 cents per kWh for surplus electricity sold by corporations, small businesses, and homeowners selling surplus electricity from wind and certain biomass energy projects
- Modified Accelerated Cost Recovery System that allows for businesses to recover investments in solar, wind, and geothermal property through depreciated deductions

For related tax forms please visit http://www.irs.gov.

6.2.1 Federal 10 Percent Investment Tax Credit

The Federal 10 Percent Investment Tax Credit, 26 USC 48, allows commercial investors in solar and certain geothermal generation projects to receive a tax credit equal to 10 percent of their investment in equipment and installation. This is not available for residential purchases. Only unsubsidized portions of the investment are eligible for the tax credit. In addition, the maximum tax deduction for any one year is $25,000 plus 25 percent of the total tax remaining. The amount of the credit may not exceed the total taxes owed; any remaining credit may be taken in other tax years. If all or part of the credit cannot be deducted because of tax liability limitations, any balance may be carried forward 15 years and backward three years from the year the balance occurred. Internal Revenue Service Form 3468 (Investment Credit), and potentially, Internal Revenue Service Form 3800 (General Business Credit), must be filed each year the solar property tax credit is taken.

Solar property eligible for the investment credit uses solar energy to generate electricity, to heat, cool, or provide hot water for use in a structure, or to provide process heat. Such property includes:

- equipment that uses solar energy to generate electricity, including storage devices, power conditioning equipment, transfer equipment and related parts, and equipment up to, but not including, the stage that transmits or uses electricity (power lines and end use appliances)

[49] This section reflects in large part the content of the following document: U.S. Department of Energy. Financial Incentives for a Business to Invest in Renewable Energy Systems. Energy Efficiency and Renewable Energy Network (EREN) Reference Briefs. 1999. www.eren.doe.gov/consumerinfor/refbriefs/la6.html.

- "dual use equipment" (equipment that uses both solar and conventional energy) that uses energy from non-solar sources that does not exceed 25 percent of the system's total energy input in an annual measuring period. Only the equipment or system cost associated with the use of solar energy qualifies for this credit. (For example, a solar photovoltaic system with a stand-by gasoline or diesel generator that provides less than 25 percent of total power supply over a one year period may qualify for the credit, but the cost of the generator must be excluded from the system cost to which the 10 percent tax credit is applied.)

In addition, solar property must be:

- completely installed and operational in the year in which the credit is first taken
- constructed, reconstructed, or erected by (or at the request of) the taxpayer
- originally used by the taxpayer, if acquired by the taxpayer
- in conformance with any performance or quality standards prescribed by regulation
- subject to depreciation or amortization

Solar property does not include:

- public utility (distribution company) property
- the material and components of "passive solar systems," even if combined with qualifying "active solar systems"
- equipment used for most swimming pools
- equipment using solar energy to generate steam at high temperatures for use in industrial or commercial processes

Geothermal property includes equipment used to produce, distribute or use energy from a geothermal deposit. It does not include public utility (distribution company) property.

The credit cannot be taken for property used mainly outside of the United States, by governmental organizations, foreign persons or entities, or tax-exempt organizations (unless the property is used mainly in an unrelated trade or business).

6.2.2 Federal Renewable Energy Production Tax Credit and Renewable Energy Production Incentive

EPAct established the Federal Renewable Energy Production Tax Credit and Renewable Energy Production Incentive to provide financial incentives to both private and public entities for wind, biomass, and potentially, solar and geothermal generation.

6.2.2.1 Renewable Energy Production Tax Credit

The production tax credit allows private entities subject to taxation (corporations, small businesses, and homeowners) to receive a 1.5 cent tax credit (in 1993 dollars and indexed for inflation) for every kWh of electricity generated from wind or biomass that they sell during the first 10 years of operation. For example, if a homeowner or small business installs a wind generator and sells 10,000 kWh of surplus electricity to a local distribution company over a year, the homeowner can apply for a tax credit equal to $150. Only those biomass power facilities that utilize biomass grown exclusively for energy production ("closed-loop" systems) can qualify for the tax credit. It is also not available for a taxpayer who cuts standing timber to produce electricity. For wind-generated electricity, the credit applies to plants brought on line between January 1, 1994 and December 31, 2001. For closed-loop biomass facilities, the credit applies to plants brought on line between January 1, 1993 and June 30, 1999. As of the date of publication for the Guidebook, the credit for biomass had not been extended. Internal Revenue Service Form 8835 Part I (Renewable Electricity Production Credit), and potentially Internal Revenue Service Form 3800 (General Business Credit) must be filed each year the renewable energy production tax credit is taken.

6.2.2.2 Renewable Energy Production Incentive (REPI)[50]

Renewable Energy Production Incentive (REPI), found at 10 CFR 451, allows for qualified state or local government-owned facilities or non-profit electric cooperatives that generate electricity using solar, wind, biomass (excluding municipal solid waste, and including landfill gas), and certain types of geothermal resources to receive an annual incentive payment of 1.5 cents per kWh (in 1993 dollars and indexed for inflation) produced during the first 10 years of operation. Eligible electric production facilities are those owned by state and local government entities (such as municipal utilities) and not-for-profit electric cooperatives that start operations between October 1, 1993 and September 30, 2003.

Qualified public projects can apply for the incentive from October through December for electricity generated during the federal government fiscal year. The payment will be allocated to recipients during the following spring. The incentive payment is legislated to run through 2003; however, funding is contingent upon annual congressional appropriations. If there are insufficient funds, payments are made first to Tier 1 QFs (solar, wind, and closed-loop biomass) and then to Tier 2 QFs (open-loop biomass and landfill gas projects).

The point of contact for questions concerning REPI policy issues and the availability of appropriations for the REPI program is Larry Mansueti, DOE, at (202) 586-2588, or Lawrence.Mansueti@ee.doe.gov. The point of contact on REPI implementation (facility qualifications, applications, and payments) is Dave Darling, NREL, at (303) 275-4795, or david_darling@nrel.gov.

6.2.2.3 Modified Accelerated Cost Recovery System

Section 168 of the Internal Revenue Code, 26 USC 168, contains a Modified Accelerated Cost Recovery System (MACRS), by which businesses can recover investments in solar, wind, and geothermal equipment through depreciation deductions. The MACRS establishes a useful class life for different types of property, ranging from three to 31.5 years. The property may be depreciated over this time. For renewable energy projects developed after 1986, the current MACRS useful class life is five years. The types of systems covered by MACRS are:

[50] Office of Power Technologies. Renewable Energy Incentive Program. http://www.eren.doe.gov/power/repi.html.

- solar property that meets the same standards for eligibility required by the federal 10 percent tax credit
- wind property, including wind turbines, wind electric generators, storage devices, power conditioning equipment, transfer equipment, and related parts, up to the electrical transmission stage, subject to the same 25 percent limit on dual-fueled equipment required for solar property
- geothermal property including equipment used to produce, distribute, or use energy derived from a geothermal deposit, but only in the case of electricity generated by geothermal power, up to the electrical transmission stage

According to the Solar Energy Industries Association,[51] the MACRS depreciates equipment over a 5-year schedule, instead of depreciating equipment over a standard 20-year period as indicated in Table 9.

Table 9: Accelerated Depreciation Schedule	
Year	**Depreciation**
Year 1	20.00%
Year 2	32.00%
Year 3	19.20%
Year 4	11.52%
Year 5	11.52%
Year 6	4.76%

Taxpayers who take advantage of the Federal Commercial Investment Tax Credit should use 95 percent, instead of 90 percent, of the original value of the equipment as the basis for depreciation. If a facility does not take the Investment Tax Credit, it should use the full 100 percent of its value as the basis for depreciation.

Table 10 illustrates the savings derived from 5-year accelerated depreciation. It assumes that the total cost of equipment and installation for the renewable generation is $100,000 and that the 10% federal tax credit taken in the first year is $10,000. Therefore, the basis for depreciation is $95,000 or 95% of $100,000.

Table 10:. Accelerated Depreciation Savings				
Year	**Percent Deduction**	**Business Tax Bracket**	**Percent of Depreciation Basis**	**Savings**
1	20.00%	34%	5.80%	$6,460.00
2	32.00%	34%	10.88%	$10,335.00
3	19.20%	34%	5.53%	$6,201.60
4	11.52%	34%	3.92%	$3,720.00
5	11.52%	34%	3.92%	$3,720.00
6	4.76%	34%	1.96%	$1,860.48
Totals	100%	34%	34.37%	$32,300.00

[51] This section reflects in large part the content of the following document: Solar Energy Industries Association. Federal 5-Year Depreciation Schedule for Solar Energy Property. www.seia.org/legdepre.htm.

In the above example, the total tax incentive recovery including the 10% federal tax credit is $42,300. The savings is based on the amount that the renewable energy owner saved on taxes by being able to depreciate the renewable generator over five years, instead of the standard twenty years.

6.3 Massachusetts Financial Incentives[52]

Massachusetts offers a number of tax incentives designed to promote the development and use of renewable energy resources. This is a brief summary of those incentives. This summary is not intended to replace consultations with a lawyer, tax preparer or the Department of Revenue, who can provide a more thorough explanation of these incentives and their availability.

For related tax forms, please visit the Massachusetts Department of Revenue at www.state.ma.us/dor/.

6.3.1 State Individual Income Tax Credit

Massachusetts provides an income tax credit for individuals who install renewable energy systems (solar or wind-powered) in their residences. Eligible renewables include solar thermal, solar water and space heat, photovoltaics, wind, and hydro systems. The credit is 15 percent of the net expenditure (including installation) for the system, or $1,000, whichever is less. If the credit is greater than the individual tax liability for one year, it can be carried over to subsequent years. The credit does not apply to commercial users (MGL c. 62, ss. 6 (d)).

Massachusetts Tax Form Schedule EC must be completed in order to receive the State Income Tax Credit.

6.3.2 State Sales Tax Exemption

State law exempts from the state sales tax the sale of equipment directly relating to any solar, wind, or heat pump system to be used as a primary or auxiliary power system for heating or otherwise supplying the energy needs of a person's principal residence in the state. The exemption does not apply to commercial users. (MGL c.64H, ss. 6(dd)).

6.3.3 Local Property Tax Exemption

A taxpayer who installs a solar or wind-powered system for heating or that otherwise supplies the energy needs of his/her residence or business is eligible for an exemption from local property tax on that system. The exemption is good for twenty years from the date of installation. (MGL c. 59, ss. 5, cl. 45).

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[52] See Massachusetts Department of Energy Resources. Massachusetts Renewable Energy Tax Credits. 1999. www.magnet.state.ma.us/doer/programs/renew/renew.htm.

6.3.4 Hydropower-Property Tax Exemption

Hydropower facilities are exempt from local property tax for a period of twenty years from the date of completion of the construction of such facility, if construction of the facility commences after January 1, 1979. To qualify for this exemption, the owner of the plant must agree to pay the host community at least 5 percent of the plant's gross income for the preceding calendar year in lieu of taxes.

The exemption applies to all real property (land and buildings) and tangible property (turbines and other equipment) necessary for the production of hydropower as described in MGL c. 59, ss. 5, cl. 45A.

6.3.5 Corporate Income Tax Deduction

A business that purchases a qualifying solar or wind-powered "climatic control unit" or "water heating unit" is allowed to deduct from its net income, for state tax purposes, any costs incurred from installing the unit, provided the installation is located in Massachusetts and is used exclusively in the trade or business of the corporation (MGL c. 63, ss. 38H.). If a project qualifies for this deduction, it may also qualify for an exemption from the corporate excise tax of $6.00 per $1,000 of assessed valuation as described in MGL c. 63, ss. 38H (f).

6.3.6 Alternative Energy and Energy Conservation Patent Exemption (Personal and Corporate)

Any Massachusetts resident who has applied for or holds a patent for an alternative energy or energy conservation system or device may petition the Commissioner of Energy Resources for determination that such patent is "...of economic value, practicable, and necessary for the convenience and welfare of the Commonwealth." If the Commissioner approves such a patent, income received from the sale, lease, or other transfer of such patent, including royalty income, and any sale, lease, or other transfer of property or materials manufactured in the Commonwealth subject to such patent, is exempt from state personal income tax or corporate excise tax. The exemption is valid for five years from the date of issuance of the patent or approval by the Commissioner of Energy Resources, whichever expires first as described in MGL c. 62, ss. 2(a)(2)(G).

6.4 Other Massachusetts Policies to Support Renewable and Distributed Generation

In addition to financial incentives and funding sources, there are three components of Massachusetts restructuring law that help to create value for renewable and distributed generation in the competitive market. These include:

- a renewable energy portfolio standard that will require a minimum percentage of retail sales to come from renewable energy
- a generation performance standard that will require retail sales to meet minimum thresholds for certain emissions

- the mandatory disclosure of electricity information, such as fuel type and emissions.

These policies are summarized below. The onset of competition will allow for the marketing of different electricity products, such as green power. Non-governmental programs concerning the certification of green power are also discussed below.

6.4.1 Renewable Energy Portfolio Standard

Massachusetts's restructuring law section (MGL, c. 25A, s. 11F) requires the Division of Energy Resources (DOER) to establish a renewable energy portfolio standard for all retail electricity suppliers. The DOER is also directed to establish a baseline of the actual percentage of kWh sales to end-use customers that is derived from existing renewable energy generation.

Beginning in 2003, every retail supplier is required to provide a minimum percentage of generation from new renewable energy sources to end-use customers according to the following schedule:

- 1.0 percent of sales in 2003
- 1.5 percent of sales in 2004
- 2.0 percent of sales in 2005
- 2.5 percent of sales in 2006
- 3.0 percent of sales in 2007
- 3.5 percent of sales in 2008
- 4.0 percent of sales in 2009
- an additional 1 percent of sales every year thereafter until a date determined by the DOER.

A qualifying new renewable energy-generating source must meet vintage and fuel requirements.

- **Vintage:** New renewable energy must have begun commercial operation after December 31, 1997, or have represented an increase in generating capacity after December 31, 1997, at an existing facility.

- **Fuel Requirement:** New renewable energy facilities must generate electricity using any of the following:

  - solar photovoltaic or solar thermal electric energy
  - wind energy
  - ocean thermal, wave, or tidal energy
  - fuel cells utilizing renewable fuels
  - landfill gas

- low-emission, advanced biomass power conversion technologies, such as gasification using such biomass fuels as wood, agricultural, or food wastes, energy crops, biogas, biodiesel, or organic refuse-derived fuel.

After conducting administrative proceedings, the DOER may add technologies or technology categories to the above list. However, coal, oil, nuclear power, and natural gas (except when used in fuel cells) cannot be classified as renewable energy for purposes of the renewable energy portfolio standard. For more information contact the DOER Public Information Officer for Renewables at (617) 727-4732 or visit www.state.ma.us/doer.

6.4.2 Generation Performance Standards

Massachusetts restructuring law requires the DEP to adopt and implement regulations for uniform generation performance standards. Under MGL Chapter 111, Section 142 N, generation performance standards will provide a cap for certain emissions produced per unit of electric output on a portfolio basis. The DEP will set standards for any pollutant that is determined to be a concern to public health, and that is produced in quantity by electric generating facilities. The uniform generation performance standards for at least one pollutant will take effect May 1, 2003, unless three or more other northeastern states enact similar legislation before that date, in which case the DEP may adopt a generation performance standard sooner.

For more information visit www.state.ma/us/dep or call the DEP at (617) 292-5500.

6.4.3 Disclosure

As detailed in 220 CMR 11.06, disclosure requirements mandate electricity suppliers to reveal information about the generation source(s) of their sales to consumers specifying information about fuel mix (coal, natural gas, hydro, wind, etc.) and emissions (nitrogen oxides, sulfur oxides, carbon dioxide, etc.).[53] This requirement will enable consumers to differentiate among different electricity products based on their cost, as well as their environmental attributes. Disclosure may help facilitate a market for green power products and enable customers to support renewable energy.

Each quarter, suppliers are required to disclose information based on the previous calendar year. If a supplier has operated for more than three months but less than one year, it may disclose information based on the period of time it has operated. Suppliers operating for less than three months may disclose information based on the supplier's contracts and generation assets and the average regional mix. Suppliers must disclose information based on known resources, system power, and imports.

- **Known Resources:** When a supplier's resource portfolio includes generation from specific generation units (for example, through a unit contract for wind verified by the ISO), or when it can verify a contract from a unit smaller than 1 MW, it can

[53] In addition, suppliers are required to disclose price, contract, and labor information.

disclose information based on the fuel and emissions characteristics of the specified unit.

- **System Power:** When a supplier's resource portfolio includes generation that is not associated with a known resource (for example power obtained through a system contract that does not specify a unit), it must assign the characteristics of the regional residual mix. Eventually Massachusetts will calculate the residual mix as the NEPOOL regional average mix minus known resources. For now, the residual mix is the NEPOOL regional average.

- **Imports:** When a supplier's resource portfolio includes generation imported from outside the NEPOOL region, this generation must be labeled as "imported" for purposes of fuel type, and it must be assigned representative emissions rates that have been determined in consultation with the DEP.

Suppliers that offer more than one product, for example, a renewable energy product and a low price product may also disclose information at the product level rather than just the company-wide level overall, provided that the information is verified by the ISO. Annually, each supplier is required to provide a report to the DTE that matches its total generation from known resources, system power, and imports with total retail sales.

For a sample disclosure label please visit http://www.magnet.state.ma.us/thepower/energy.htm.

6.4.4 Green Power Certification

Developers of renewable energy that are interested in selling renewable energy directly to suppliers or retail customers should be aware of initiatives concerning the retail marketing of green power. Massachusetts has not developed actual certification standards for the sale of green power in the competitive market. However, non-governmental organizations are developing programs in other states to certify green power products in order to help educate customers and add credibility to green power offerings. These initiatives provide examples of the types of green power certification programs that might evolve in Massachusetts. For instance, the Green-e certification program, founded in California by the Center for Resource Solutions, certifies green power products using the state of California's definition of renewable energy. Under the California definition, eligible renewable resources include: wind, solar, geothermal, small hydroelectric (less than 30 MW), and biomass (including landfill gas).

The initial Green-e standard for California requires that:

- The product must contain 50 percent or more renewables content averaged over one year
- The fossil portion (if any) of an eligible product must have air emissions (SO_2, NO_x, and CO_2) equal to or lower than emissions from an equivalent amount of the system average

- Air emissions from a renewable energy generator that uses waste materials for fuel must be equal to or less than the emissions that would otherwise be produced from the most common alternative disposal of the waste, plus the emissions associated with producing an equivalent quantity of system power
- The product must not contain any nuclear power other than what is contained in system power purchased for the eligible product's portfolio

In addition, a specification has been added that requires a percentage of Green-e labeled electricity to come from new facilities.

Green-e standards are currently under consideration for New England. For additional information, visit the Green-e website at http://www.green-e.org.

7.0 Case Studies of Renewable Energy and Distributed Generation Projects

The following case studies are presented to help developers of various types of renewable energy and distributed generation to understand the process for:

- contracting to sell power to the local distribution company
- siting and permitting
- interconnection and metering.

In each case study, these processes all took place at the same time.

The following five case studies explore the development of:

- a 15 kW solar electric generating station
- a 1.5 MW piston engine generator that uses methane gas from a landfill
- a 200 kW fuel cell that uses methane gas from a landfill
- a 6.5 MW wind power project
- a 125 MW natural gas fired cogeneration facility.

Please note that these case studies are derived from real life examples as well as hypothetical situations.

For a sample list of actual operational renewable generation projects in Massachusetts please refer to Appendix Seven.

7.1 15 kW Solar Electric Generating Station

XYZ, which is not affiliated with an investor-owned distribution company, developed a 15 kW solar generating system on top of donated commercial roof space from Acme. The system consists of over 60 separate photovoltaic panels that produce an estimated 19,500 kWh per year. XYZ sells output to both the local distribution company and to the commercial host.

- **Contracting for power sales:** The solar generating system meets the criteria for a QF because more than 75% of its fuel is from a renewable resource --- solar power. In addition, no investor-owned distribution company owns an equity interest in the facility. XYZ qualifies for net metering in Massachusetts because its generating capacity is 60 kW or less. Because of its size, XYZ opted to skip the QF process and arranged for net metering with its local distribution company. Arranging for net metering took approximately two to three months.

- **Siting and Permitting:** The solar generating system does not meet any of the threshold requirements for the EFSB, MEPA, or DEP permits, and is therefore not subject to their jurisdiction. However, XYZ needed to apply for a town building permit. In certain cases, photovoltaic installations that are highly visible to the public may have some difficulty receiving approval, but in this case, the photovoltaic system is located on a flat roof and is not readily visible to the public. The building permit process took about one to two months. In addition, pursuant to some federal funding the project received, XYZ was required to fill out a NEPA determination form. It was determined that the project was exempt from NEPA.

- **Interconnection and Metering:** XYZ worked with the account manager of Acme's distribution company and the distribution company's engineers to ensure that all safety and administrative requirements for interconnection were met. The interconnection for this project took about two to three months, but there were no standard forms or procedures for processing the interconnection. The interconnection process varies with each distribution company. XYZ uses a revenue quality meter combined with a data acquisition system and modem for downloading production data every 15 minutes.

- **Other Policies and Programs:** XYZ received a funding award from the UPVG "Team-up Program." In addition, XYZ sells its electrical output and associated green characteristics to green power marketers who in turn sell green power products to retail customers. This green power marketing is supported by disclosure requirements. In addition, once the renewable portfolio standard takes effect, output from the solar energy system will count towards the standard. While the Massachusetts Renewable Energy Trust Fund is not yet allocating significant funds, XYZ has had similar projects in other states that qualify for funding from these states' renewable energy funds.

7.2 200 kW Fuel Cell That Uses Landfill Gas

Recently, a municipal electricity provider, Municipal Electric Co., began generating electricity from a 200 kW fuel cell located at the now-closed town landfill. The fuel cell uses methane gas, naturally produced by decaying matter in the landfill, to generate electricity. It is estimated that the landfill will provide enough methane gas for the fuel cell to operate for 20 years. As the amount of methane gas diminishes over time, the energy supply for the fuel cell will be supplemented with natural gas. The fuel cell is connected to the Municipal Electric Co. distribution grid and provides enough electricity to service over 75 residential homes.

- **Contracting for Power Sales:** The fuel cell does not qualify for net metering because it is greater than 60 kW. Although the fuel cell meets the criteria for a QF, the fuel cell is used only to reduce electricity load for the town. As a result, the QF process was not undertaken. Municipal Electric Co. is now examining the possibility of selling renewable energy from the fuel cell to Municipal Electric Co. customers as a green pricing option. This is a requirement of the American Public Power Association (APPA) DEED grant program (see below).

- **Siting and Permitting:** The fuel cell generating system does not meet any of the threshold requirements for the EFSB or MEPA, and was therefore not subject to their jurisdiction. However, because of the project's need to modify a previously closed landfill, Municipal Electric Co. had to submit an extremely detailed project description to the DEP in order to modify the landfill's closure plan. This process took approximately one year from start to finish. In addition, in upgrading feeder lines to support the fuel cell generating system, Municipal Electric Co. had to follow local regulations in concert with the Massachusetts Wetlands Protection Act. Relevant regulations pertained to the following categories: public water supply; private water supply; ground water supply; flood control; storm damage prevention; prevention and pollution; erosion and sedimentation control; and protection of wildlife. Additionally, the local Board of Health was concerned about the noise level of the fuel cell. After receiving assurances from Municipal Electric Co. that the noise emitted from the fuel cell would be equivalent to a window air conditioner, less than 60 decibels at 30 feet, Municipal Electric Co. was granted permission to operate the fuel cell at any output level.

- **Interconnection and Metering:** Interconnection and metering procedures were not an issue because Municipal Electric Co., which is also the distribution company, installed the fuel cell to act as a load reducer for the town electricity load. Interconnection with the ISO was not applicable. The physical logistics of interconnection with the distribution area were challenging, however. But this challenge was a result of the Municipal Electric Co.'s decision to upgrade service to the whole area at the same time as it installed its fuel cell. Coincident with the fuel cell installation, Municipal Electric Co. upgraded one of its feeder lines to increase reliability to customers on that line while also connecting it to the fuel cell. The distribution company installed standard bi-directional Quad 4 metering, which can be read automatically from a computer in the Municipal Electric Co. office.

- **Other Policies and Programs:** Municipal Electric Co. received funding from a variety of sources for its fuel cell project. These sources included a federal grant from the DOE in the amount of $200,000, a state grant from the Massachusetts DOER in the amount of $100,000, and a $10,000 DEED grant through the APPA. The DOE also has a rebate program for fuel cells that provides a 1.7 cent per kWh rebate.

7.3 1.5 MW Piston Engine Generator Using Methane Gas from a Landfill

Power Co. is an independent power producer that is not affiliated with an investor-owned distribution company. Power Co. developed a 1.5 MW piston engine generator from used equipment that uses methane gas from a landfill to produce electricity. The project is located adjacent to the landfill.

- **Contracting for power sales:** The project met the criteria for a QF. Power Co. self-certified as a QF with FERC, and is receiving the ISO market price for electricity. The project's electricity output is metered at the point of delivery, so the project is not charged for line losses.

- **Siting and Permitting:** The 1.5 MW Piston Engine Generator did not meet any of the threshold requirements for the EFSB or MEPA permits and was therefore not subject to their jurisdiction. Power Co. did need to obtain an Air Plans Approval permit from the DEP Division of Air Quality Control because the project has a heat rating that exceeds 3 million Btu/hr. The DEP determined the best available pollution control technology for the project. Power Co. demonstrated that its use of this control technology would enable it to comply with federal and state air quality guidelines. This process took about six months. In addition, Power Co. needed to apply for a town building permit.

- **Interconnection and Metering:** Power Co. worked with the local distribution company to interconnect its project into the distribution system. It was determined that the existing distribution system had enough capacity to support the project, so the local distribution company only focused on preparing a plan and budget estimate for interconnection. Power Co. paid for the interconnection. The interconnection process took about six months. Most of this time was spent preparing and reviewing the interconnection design. The Power Co. received a revenue quality time-of-use meter from a local distribution company that provides interval data and that can be accessed via modem.

- **Other Policies and Programs:** The landfill gas project was built early enough so that it was grandfathered into the Federal Renewable Energy Production Tax Credit for biomass energy. Power Co. receives a credit of approximately 1.5 cents per kWh generated by the project. In addition, Power Co. sells its generation and associated renewable energy characteristics to retail power suppliers that market the power as part of their green power products.

7.4 25 MW Natural Gas-Fired Combined Cycle Cogeneration Facility

Modern Industries serves as a steam host for a 120 MW gas-fired combined cycle facility. The project is located next to a river. The topping cycle cogeneration facility is fired by an interruptible supply of natural gas. Distillate oil is used as the back-up resource. The total annual electrical production is about 1,000,000 MWh. The facility's fuel consumption is about 25 thousand cubic feet of natural gas.

The facility is located in a rural area, approximately 16,000 feet from the nearest airport runway. The terrain is hilly and higher than the facility's stack. The facility is considered a major new source of air contaminants.

The facility does not require any more water than Modern Industries used before the cogeneration facility was developed. The facility uses process water for cooling water. Most water disperses into the atmosphere, with the remaining discharge into the municipal sewage system. This results in less wastewater discharge back into the river. The facility is located 1.5 miles from a 115 kV transmission line which is accessed across wetlands. A natural gas pipeline already existed on site.

- **Contracting for power sales:** The project met criteria for a QF. The annual power generated plus half of the useful thermal output is more than 42.5% of the natural gas input. More than 15% of the energy output of the facility is useful thermal output. In this case, Modern Industries self-certified as a QF with FERC. If Modern Industries had any uncertainty as to whether it qualified as a QF, it could have requested certification of QF status by FERC.

In this example, QF status is almost irrelevant. The facility is large enough to directly sell power into the ISO power exchange and therefore does not need to sell electricity to a local distribution company through a QF standard contract. Modern Industries also signed a long-term power contract with a power supplier for a portion of its electricity output.

- **Siting and Permitting:** The facility required approval from the EFSB because it is greater than 100 MW and required the construction of a transmission line that is greater than 69 kV. Modern Industries demonstrated that the site is optimal relative to alternative sites, and that the facility used an efficient and environmentally sound generation technology. In addition, Modern Industries demonstrated that the route for the transmission line is optimal relative to other routes.

  The project was categorically included by MEPA standards. Modern Industries filed an ENF and an EIR. The draft EIR responded to issues prepared by MEPA in response to the ENF. Modern Industries finished the MEPA process by submitting a Final EIR.

  In addition, Modern Industries needed to address a number of state, federal, and local permit issues, including the following:

  - Air Plans Approval from the DEP Air Program Planning Unit --- the cogeneration project has a heat rating input exceeding 3 million Btu/hour
  - Sewer Connection and Extension Permit from the DEP Water Pollution Control Program--- the project connects to a public sewer system
  - Chapter 21G Permit from the DEP Drinking Water Program --- the facility diverts more than 100,000 gallons per day from a river
  - Oil Storage Tank Permit from the Department of Public Safety --- the facility stores distillate oil in excess of 10,000 gallons
  - Chapter 91 Permit from the DEP Wetlands and Waterways Program --- the new transmission lines pass through a wetland
  - Wetlands Permit from the Corps of Engineers --- the new transmission lines pass through a wetland
  - FAA Notice of Proposed Construction --- the facility is located within 20,000 feet of an airport
  - Local Permits --- Permits (order of conditions) were needed from the local conservation commission; other permits also were needed from the local building inspector, zoning Board of Appeals, and fire inspector

- **Interconnection and Metering:** The project required interconnection to the transmission system. It also needed to interface with the ISO in order to sell power into the ISO transmission system. This required bi-directional, interval metering.

Appendix One: Glossary

Word	Definition
Access Charge	A charge levied on power supplied or on an electricity customer for access to a utility's transmission or distribution system for the right to send electricity over another's wires.
Bilateral Contract	A direct contract between the power producer and user or broker outside of a centralized power pool or POOLCO.
Bottoming-cycle Facility	A cogeneration facility in which the energy input to the system is first applied to a useful thermal energy application or process, and at least some of the reject heat emerging from the process is then used for electric power production.
Broker	A retail agent who buys and sells power. The agent may also aggregate customers and arrange for transmission, firming and other ancillary services as needed.
Bulk Power Supply	Often this term is used interchangeably with wholesale power supply. In broader terms, it refers to the aggregate of electric generating plants, transmission lines, and related-equipment. The term may refer to those facilities within one electric utility, or within a group of utilities in which the transmission lines are interconnected.
Cogeneration Facility	A facility that produces electric energy and steam or forms of useful energy (such as heat) which are used for industrial, commercial, heating, or cooling purposes.
Competitive Supplier	An entitiy that is licensed by DTE to sell electricity and related services to retail customers.
Congestion	A situation in which heavy flows of electricity over distribution or transmission wires result in intense demands being placed on the system. Congestion is relieved through activation of a congestion management plan.
Demand-Side Management (DSM)	Planning, implementation, and evaluation of utility-sponsored programs to influence the amount or timing of customers' energy use.
Distributed Generation (DG)	An electric generation facility or technology that is located in proximity to electric loads and is either connected directly to the electric load or is interconnected to the electric grid at the distribution system level. Examples of DG facilities include: rooftop photovoltaic systems, fuel cells, cogeneration or combined heat and power systems, natural gas-fired micro-turbines, and small wind turbines.
Distribution	The delivery of electricity to the retail customer's home or business through distribution lines, at voltages lower than used on transmission lines.
Distribution Utility (Disco)	The regulated electric utility entity that constructs and maintains the distribution wires connecting the transmission grid to the final customer. The Disco can also perform other services such as aggregating customers, purchasing power supply and transmission services for customers, billing customers and reimbursing suppliers, and offering other regulated or non-regulated energy services to retail customers. The "wires" and "customer service" functions provided by a distribution utility could be split so that two totally separate entities are used to supply these two types of distribution services.
Electricity Information Disclosure	A policy that requires electricity suppliers to provide information to consumers about the sources, emissions, or other characteristics of their electricity supply in the Disclosure Label included with customers' bills and marketing materials.
Electricity Supplier	Any entity that generates and sells electricity to another entity.

Electric Utility	Any person or state agency with a monopoly franchise (including any municipality), which sells electric energy to end-use customers; this term includes the Tennessee Valley Authority, but does not include other Federal power marketing agencies (from EPAct).
Energy Efficiency	Using less energy/electricity to perform the same function. Programs designed to use electricity more efficiently -- doing the same with less. For the purpose of this guidebook, energy efficiency is distinguished from DSM programs in that the latter are utility-sponsored and -financed, while the former is a broader term not limited to any particular sponsor or funding source. "Energy conservation" is a term which has also been used, but it has the connotation of doing without in order to save energy rather than using less energy to do the same thing and so is not used as much today. Many people use these terms interchangeably.
Exempt Wholesale Generator (EWG)	As outlined under EPAct, an electricity producer that is permitted to generate and sell electricity at wholesale prices without being regulated as a utility under PUHCA.
Exit Fee	A fee charged by a distribution company to customers that develop on-site generation to offset the impact that their leaving has on the distribution company's overall revenues, and in turn the regulated rates of its other customers.
Financial Congestion Rights (FCRs)	A financial mechanism that can be purchased by market participants to enable them to hedge against the risks associated with congestion costs by locking in certain rates.
Fuel Cell	An electrochemical device that converts chemical energy into electrical energy without combustion and releasing only pure water into the atmosphere. The reactants in this conversion are hydrogen (fuel) and oxygen (oxidant). Fuel cells can run on natural gas and other fossil fuels with significantly reduced pollutants. B28
Generation	The production of electricity by power plants.
Generation Company	A regulated or non-regulated entity (depending upon the industry structure) that operates and maintains existing generating plants. The generation company may own the generation plants or interact with the short term market on behalf of plant owners.
Generation Performance Standard	A policy that requires retail electricity sales to meet minimum thresholds for certain emissions.
Grid	A system of interconnected power lines and generators that is managed so that the generators are dispatched as needed to meet the requirements of the customers connected to the grid at various points. Gridco is sometimes used to identify an independent company responsible for the operation of the grid.
Interconnection	The process by which small facilities interconnect with a distribution company, or by which large QFs or other power producers interconnect with the transmission system directly.
Independent Power Producer (IPP)	A private entity that operates a generation facility and sells power to electric utilities for resale to retail customers.
Independent System Operator (ISO)	A neutral operator responsible for maintaining instantaneous balance of the grid system. The ISO performs its function by controlling the dispatch of flexible plants to ensure that loads match resources available to the system.
Investor Owned Utility (IOU)	A company owned by stockholders for profit that provides utility services. A designation used to differentiate a utility owned and operated for the benefit of shareholders from municipally owned and operated utilities and rural electric cooperatives.

Islanding	A potentially dangerous situation in which an electricity generator remains energized even after the main system goes down. Grid-tied inverters generally have built-in safety features to protect against islanding.
Known Resources	Information disclosure requirements that apply to specific generation units operated by an electricity supplier.
Load Centers	A geographical area where large amounts of power are drawn by end-users.
Marginal Cost	In the utility context, the cost to the utility of providing the next (marginal) kilowatt-hour of electricity, irrespective of sunk costs.
Market-Based Price	A price set by the mutual decisions of many buyers and sellers in a competitive market.
Microturbine	Any of a variety of small scale electricity generating devices that produces electricity efficiently and cost-effectively, while emitting very low levels of pollutants and remaining virtually maintenance free. Microturbines are capable of running off a variety of fuels, including natural gas, propane, and diesel to produce electricity.
Multi-settlement System	A settlement system by which day-ahead bids are used for both scheduling and day-ahead transactions, and only deviations from the day-ahead schedule are priced afterwards.
Municipal Utility	A provider of utility services that is owned and operated by a municipal government.
Net Metering	A process by which a small scale electricity generator sells surplus electricity back to its associated distribution company.
On-Site Generating Facility (OSGF)	Any independent electricity generating facility with a capacity of 60 kW or less.
Open Access Same-Time Information System (OASIS)	An information system mandated by FERC Order 889 that provides information to RTO market participants about electric transmission capacity availability.
Peak Load or Peak Demand	The electric load that corresponds to a maximum level of electric demand in a specified time period.
Power Pool	An entity established to coordinate short-term operations to maintain system stability and achieve least-cost dispatch. The dispatch provides backup supplies, short-term excess sales, reactive power support, and spinning reserve. Historically, some of these services were provided on an unpriced basis as part of the members' utility franchise obligations. Coordinating short-term operations includes the aggregation and firming of power from various generators, arranging exchanges between generators, and establishing (or enforcing) the rules of conduct for wholesale transactions. The pool may own, manage and/or operate the transmission lines ("wires") or be an independent entity that manages the transactions between entities. Often, the power pool is not meant to provide transmission access and pricing, or settlement mechanisms if differences between contracted volumes among buyers and sellers exist.
PUHCA	The Public Utility Holding Company Act of 1935. This act prohibits acquisition of any wholesale or retail electric business through a holding company unless that business forms part of an integrated public utility system when combined with the utility's other electric business. The legislation also restricts ownership of an electric business by non-utility corporations.

PURPA	The Public Utility Regulatory Policy Act of 1978. Among other things, this federal legislation requires utilities to buy electric power from private "qualifying facilities," at an avoided cost rate. This avoided cost rate is equivalent to what it would have otherwise cost the utility to generate or purchase that power themselves. Utilities must further provide customers who choose to self-generate a reasonably priced back-up supply of electricity.
Qualifying Facility (QF)	Under PURPA, QFs have been allowed to sell their electric output to the local utility at avoided cost rates. To become a QF, the independent power supplier had to produce electricity with a specified fuel type (cogeneration or renewables), and meet certain ownership, size, and efficiency criteria established by the Federal Energy Regulatory Commission.
Real-Time Pricing	The instantaneous pricing of electricity based on the cost of the electricity available for use at the time the electricity is demanded by the customer.
Regional Transmission Operators	An independent transmission system operator that meets certain criteria, including those related to independence and market size, established by FERC Order 2000.
Reliability	Electric system reliability has two components -- adequacy and security. Adequacy is the ability of the electric system to supply the aggregate electrical demand and energy requirements of the customers at all times, taking into account scheduled and unscheduled outages of system facilities. Security is the ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system facilities.
Renewable Energy	Certain types of energy sources for an electric generation facility or technology that are naturally replenishable in a relatively short time period. They include biomass (e.g. wood), geothermal, hydropower, solar, tidal, wave and wind.
Renewable Portfolio Standard (RPS)	A policy mechanism that requires electricity suppliers to include a certain percentage of renewable energy in their electricity portfolio.
Renewable Resources	Renewable Energy Resources are ones which derive from the natural movements and mechanisms of the earth and are naturally replenishable at a rate proportionate with their rate of use. Renewable energy resources include sunlight, wind, biomass, moving water, and the heat of the earth.
Restructuring	The reconfiguration of the vertically-integrated electric utility. Restructuring usually refers to separation of the various utility functions into individually-operated and -owned entities.
Retail Competition	A scenario under which more than one electric provider can sell power to retail customers, and retail customers are allowed to buy power from more than one provider (See also Direct Access).
Retail Electricity Market	A market in which electricity and other energy services are sold directly to the end-use customer.
Retail Wheeling	A policy which permits retail electric customers to choose their generation from any available source.
Single Settlement System	A settlement system by which day-ahead bids are used for scheduling, but prices are determined afterwards, based on real-time dispatch.
Short-Run Rate	The hourly market clearing price for energy and capacity, as determined by the ISO.
Spot Market	A market for commodity transactions in which the transaction begins near term (i.e., within ten days) and the contract duration is short (i.e., thirty days).
Stranded Costs	See "Transition Costs."

System Power	Information disclosure requirements when a supplier's resource portfolio includes generation that is not associated with a known resource. In such cases, that power is assigned the characteristics of the regional residual mix.
System Transaction	Contracts between two companies that do not specify a specific unit that is obligated to serve the contract, and, as such, are "portfolio" contracts. The duration of contracts will vary. System transactions are usually in the form of bilateral contracts.
Tariff	A document, approved by the responsible regulatory agency, listing the terms and conditions, including a schedule of prices, under which utility services will be provided.
Topping-cycle Facility	A cogeneration facility in which the energy input into the facility is first used to produce useful electric power output, and at least some of the reject heat from the power production process is then used to provide useful thermal energy.
Transition Cost	A distribution company's recovery of past costs including investments made in generating plants and power contracts. The exact charge varies for each distribution company. Now a separate charge in customers' bills, it will decrease over time as these costs are paid off. Sometimes referred to as "stranded costs."
Transmission	Typically refers to the movement of wholesale electricity from the site of generation to distribution companies via high voltage power lines.
Transmitting Utility (Transco)	A regulated entity which owns, and may construct and maintain, wires used to transmit wholesale power. It may or may not handle the power dispatch and coordination functions. It is regulated to provide non-discriminatory connections, comparable service, and cost recovery. According to EPAct, this includes any electric utility, qualifying cogeneration facility, qualifying small power production facility, or Federal power marketing agency which owns or operates electric power transmission facilities which are used for the sale of electric energy at wholesale.
Unbundling	Disaggregating electric utility service into its basic components and offering each component separately for sale with separate rates for each component. For example, generation, transmission and distribution could be unbundled and offered as discrete services.
Utility	A regulated entity that exhibits the characteristics of a natural monopoly. For the purposes of electric industry restructuring, "utility" refers to the regulated, vertically-integrated electric company. "Transmission utility" refers to the regulated owner/operator of the transmission system only. "Distribution utility" refers to the regulated owner/operator of the distribution system which serves retail customers.
Vertical Integration	An arrangement whereby the same company owns all the different aspects of making, selling, and delivering a product or service. In the electric industry, it refers to the historically common arrangement whereby a utility would own its own generating plants, transmission system, and distribution lines to provide all aspects of electric service.
Wholesale Competition	A system whereby a distributor of power would have the option to buy its power from a variety of power producers, and the power producers would be able to compete to sell their power to a variety of distribution companies.
Wholesale Power Market	The purchase and sale of electricity from generators to resellers (who sell to retail customers) along with the ancillary services needed to maintain reliability and power quality at the transmission level.
Wires Charge	A broad term which refers to charges levied on power suppliers or their customers for the use of the transmission or distribution wires.

Appendix Two: Acronyms

Acronym	Name
AC	Alternating-Current
ACEC	Area of Critical Environmental Concern
AGC	Automatic Generation Control
CEQ	Council on Environmental Quality
CFR	Code of Federal Regulations
CMR	Code of Massachusetts Regulations
COE	Corps of Engineers
CWA	Clean Water Act
CZMA	Coastal Zone Management Act
DC	Direct-Current
DEM	Department of Environmental Management
DEP	Department of Environmental Protection
DFW	Division of Fisheries and Wildlife
DG	Distributed Generation
DOE	Department of Energy
DOER	Division of Energy Resources
DPS	Department of Public Safety
DPW	Department of Public Works
DTE	Department of Telecommunications and Energy
EA	Environmental Assessment
ECP	Energy Clearing Price
EFCN	Environmental Finance Center Network
EFIN	Environmental Financing Information Network
EFP	Environmental Finance Program
EFSB	Energy Facilities Siting Board
EIR	Environmental Impact Report
EIS	Environmental Impact Statement
ENF	Environmental Notification Forms
EOEA	Executive Office of Environmental Affairs
EOTC	Executive Office of Transportation and Construction
EPA	Environmental Protection Agency
EPAct	Energy Policy Act

EREN	Energy Efficiency and Renewable Energy Network
ESPCs	Energy Savings Performance Contracts
EWG	Exempt Wholesale Generator
FAA	Federal Aviation Administration
Fannie Mae	Federal National Mortgage Association
FEMA	Federal Emergency Management Administration
FEMP	Federal Energy Management Program
FERC	Federal Energy Regulatory Commission
FONSI	Finding of No Significant Impact
FPA	Federal Power Act
HHV	Higher Heating Value
HUD	Housing and Urban Development
ICAP	Installed Capability
IEEE	Institute of Electrical and Electronics Engineers
ISO	Independent System Operator
kWh	kilowatt-hours
LFG	landfill gas
LGOP	Landfill Gas Outreach Program
MACRS	Modified Accelerated Cost Recovery System
MEPA	Massachusetts Environmental Policy Act
MGL	Massachusetts General Law
MHC	Massachusetts Historical Commission
MNHP	Massachusetts Natural Heritage Program
MTPC	Massachusetts Technology Park Corporation
NEC	National Electric Code
NEPA	National Environmental Policy Act
NEPOOL	New England Power Pool
NESEA	North East Sustainable Energy Association
NFPA	National Fire Protection Association
NICE3	National Industrial Competitiveness Through Energy, Environment, and Economics
NOAA	National Oceanic and Atmospheric Administration
NPC	Notices of Project Change
NPCMS	NEPOOL Participants Committee Membership Committee
NPDES	National Pollutant Discharge Elimination System
OASIS	Open Access Same-Time Information System

OPCAP	Operable Capability
OSGF	On-Site Generation Facility
PC	Public Comment
PGP	Programmatic General Permits
POTW	Publicly Owned Treatment Works
PTF	Pool Transmission Facilities
PUHCA	Public Utility Holding Company Act
PURPA	Public Utility Regulatory Policies Act
QF	Qualifying Facility
RAS	Reliability Administration Service
RCRA	Resource Conservation and Recovery Act
RE	Renewable Energy
REPI	Renewable Energy Production Incentive
RERL	Renewable Energy Research Laboratory (U Mass Amherst)
SBA	Small Business Administration
SEIA	Solar Energy Industries Association
SIC	Standard Industrial Classification
SIS	System Impact Study
TMNSR	Ten Minute Non-Spinning Reserve
TMOR	Thirty Minute Operating Reserve
TMSR	Ten Minute Spinning Reserve
UL	Underwriters Laboratories

Appendix Three: Contact List

Organization	Last Name	First Name	Title	Address	Phone	Fax	Email	Web
Distribution Companies								
Boston Edison			Customer Service	800 Boylston Street, Boston, MA 02199	800-592-2000			www.bedison.com
	Butterfield	Dan		800 Boylston Street, unit 10, Boston, MA 02199	781-441-8627			www.bedison.com
Com/Electric				2421 Cranberry Highway, Wareham, MA 02571	800-642-7070			www.comelectric.com
Eastern Edison	Dufault	Don	Director, Transmission and Distribution		508-559-2000 x3250		ddufault@eua.com	www.eua.com
Fitchburg Gas and Electric (owned by UNITIL)			Customer Service	285 John Fitch Highway, Fitchburg, MA 01420	888-301-7700			www.utilicorp.com/profile/fitchbu.htm
Mass Electric			Customer Service	55 Bearfoot Rd, Northborough, MA 01532-1555	800-465-1212	508-357-4730	masselectric@neesnet.com	www.masselectric.com
Nantucket Electric				2 Fairgrounds Road, Nantucket, MA 02554	888-444-6326	508-325-8100	nantucketelectric@neesnet.com	www.nantucketelectric.com

Western Mass Electric	Clarke	Doug	Senior Account Executive	P.O. Box 2010, West Springfield, MA 01090	413-785-5817	413-787-9352		www.wmeco.com
			Customer Service	P.O. Box 2010, West Springfield, MA 01090	800-286-2000			www.wmeco.com
State Agencies/ Programs								
Division of Energy Resources	Public Information Officer for Renewables			70 Franklin Street, 7th Floor, Boston, MA 02110-1313	617-727-4732	617-727-0093	energy@state.ma.us	www.magnet.state.ma.us/doer
Department of Environmental Protection (DEP)			Permitting Info	1 Winter Street, Boston, MA 02108	617-338-2255		dep.infoline@state.ma.us	www.state.ma.us/dep
DEP Air Program Planning Unit	Boiselle	Robert	Permitting	1 Winter Street, Boston, MA 02108	617-292-5609		Robert.Boiselle@state.ma.us	www.state.ma.us/dep/bwp/daqchom.htm
DEP Business Compliance Division-Hazardous Waste	Paterson	James		1 Winter Street, Boston, MA 02108	617-556-1096		James.Patteson@state.ma.us	www.state.ma.us/dep/bwp/dhm/dhmhome.htm
DEP Business Compliance Division-Solid Waste	Cooper	Greg		1 Winter Street, Boston, MA 02108	617-292-5988		Greg.Cooper@state.ma.us	www.state.ma.us/dep/bwp/dswm/dswmhome.htm
DEP Drinking Water Program	Tennant	Marie		1 Winter Street, Boston, MA 02108	617-292-5885		marie.tennant-EQE@state.ma.us	www.state.ma.us/dep/brp/dws/dwshome.htm

DEP Water Pollution Program	White	Ron	Environmental Engineer	1 Winter Street, Boston, MA 02108	617-292-5790		ron.white@state.ma.us	www.state.ma.us/dep/brp/wm/wmhome.htm
DEP Wetlands and Waterways Program	Stroman	Michael		1 Winter Street, Boston, MA 02108	617-292-5526		Michael.Stroman@state.ma.us	www.state.ma.us/dep/brp/ww/rpwwhome.htm
Department of Public Safety				McCormack State Office Building, One Ashburton Place, roon 1301, Boston, MA 02108	617-727-3200	617-727-5732		www.state.ma.us/dps
Department of Telecommunications and Energy (DTE)			Electric Power Division	One South Station, Boston, MA 02110	617-305-3575			www.state.ma.us/dpu
DTE Energy Facilities Siting Board	Febiger	Bill	Assistant Director	One South Station, Boston, MA 02110	617-305-3525	617-443-1116	bill.febiger@state.ma.us	www.state.ma.us/dpu/siting_board.htm
EOEA Division of Coastal Zone Management	Skinner	Tom	Director	100 Cambridge Street, Boston, MA 02202	617-626-1200	617-626-1240	mczm@state.ma.us	www.state.ma.us/czm
Executive Office of Transportation and Construction				10 Park Plaza, suite 3170, Boston, MA 02116	617-973-7000	617-523-6454		www.eotc.org
Massachusetts Historical Commission	Bell	Ed	Archaelogist	220 Morrissey Blvd, Boston, MA 02125	617-727-8470	617-727-5128	ed.bell@sec.state.ma.us	www.magnet.state.ma.us/sec/mhc

Massachusetts Natural Heritage Program	Maher	Amy	Wetlands Environmental Review Assistant	Division of Fisheries and Wildlife, Rt 135, Westborough, MA 01581	508-792-7270 x200	508-792-7275		www.state.ma.us/bfwele/dfw
Massachusetts Renewable Energy Trust Fund				Massachusetts Technology Collaborative, 75 North Drive, Westborough, MA 01581	508-870-0312	508-870-0312		www.mtpc.org
MEPA	Hutchins	Janet	Assistant Director	100 Cambridge Street, room 2000, Boston, MA 02202	617-626-1023	617-626-1181	janet.hutchins@state.ma.us	www.state.ma.us/mepa
Federal Agencies/ Programs								
Federal Aviation Administration			Regional Air Traffic and Air Space Manager	12 New England Executive Park, Burlington, MA 01803	781-238-7520			www.faa.gov/region/ane.htm
Federal Emergency Management Administration			Region I Office	JW McCormack Post Office and Courthouse Building, room 442, Boston, MA 02109-4595	617-223-9540	617-223-9519		www.fema.gov/Reg-1/regi.htm

Federal Energy Regulatory Commission (FERC)			Public Reference Room	888 First St, NE, Washington, DC 02000	202-208-1371			www.ferc.fed.us/public/dobus1.htm
National Renewable Energy Laboratory (NREL)	Darling	Dave		1617 Cole Blvd, Golden, CO 80401-3393	303-275-4795		david_darling@nrel.gov	www.nrel.gov
U.S. Army Corps of Engineers			NE Office	USACE, New England District Regulatory Branch, 696 Virginia Road, Concord, MA 01742	800-362-4367			www.nae.usace.army.mil
U.S. Department of Energy (DOE)			Boston Regional Office	JFK Federal Building, suite 675, Boston, MA 02203	617-565-9700	617-565-9723		www.eren.doe.gov/bro
U.S. DOE Renewable Electric Plant Information System	Mansueti	Larry	REPI Policy		202-586-2588		Lawrence.Mansueti@ee.doe.gov	www.eren.doe.gov/repis
Other								
Independent System Operator- New England	Kazin	Craig	Customer Service		413-535-4124	413-535-4156	custserv@iso-ne.com	www.iso-ne.com
North East Sustainable Energy Association (NESEA)	Tower	Jonathan		50 Mile St, Greenfield, MA	413-774-6051			
UMass Renewable Energy Research Lab	Manwell	Jim	Director		413-545-4359		manwell@ecs.umass.edu	
	Bolgen	Nils	Windpower in MA		617-727-4732 x178 (800-351-0777 in MA)		John.Cosmas@state.ma.us	

	Bernstein	Howard	Biofuels Program Manager	617-727-4732 x155 (800-351-0777 in MA)		Howard.Bernstein@state.ma.us

Appendix Four: Types of Permits

Agency	Permit	Issue	Triggering Criteria
Section 3.0: Selling Power from Renewable and Distributed Generation			
Federal			
FERC	QF Certification, Self-certification, and Re-certification	Certification as a Qualifying Facility	- < 50% utility owned - For small power facilities, size not > 80 MW and energy source is biomass, waste, renewable resource or geothermal - For cogeneration facilities meets efficiency standards
State			
MA DTE	QF Contract	QF Sales to MA Utilities	- Qualify as a QF under federal criteria - Purchase arrangement depends on size
	Net Metering Agreement	Net Metered Sales to Utilities	- Capacity < 60 kW - OSGF status
Section 4.0: Siting and Environmental Permitting Process			
Federal			
NEPA	Certification	Environmental Impact Assessment	- Significant environmental impact, as determined through consultation with the Council on Environmental Quality
US Army Corps of Engineers	Section 10 Permit	Construction in Navigable Waters	- Construction of intake and discharge structures in navigable waters - Offshore wind or transmission lines in water
	Section 404 Permit	Dredging or Filling	- Discharge of dredged or fill materials into US waters
US EPA	NPDES Permit	Point Source Discharge into Navigable Waterways	- Discharge of sanitary waste or gray water, toxic pollutants including pesticides and metals, and non-conventional pollutants
FAA	FAA Approval	Proximity to Airport Runway and Stack Height	- Facility located within 20,000 feet of airport runway - Proposed stack height >200 feet
FEMA	FEMA Restrictions and Requirements	Flood Plain Development	- Facility sited within the 100-year flood plain

State			
MEPA	Certification	Environmental Impact Assessment	- Size > 25 MW - Includes new fuel pipeline > 5 miles - Includes new transmission lines > 69 kV or more and > 1 mile - Significant land/ species habitat alteration, water withdrawal, sewer construction, waste disposal, air emissions, combustion/ disposal of hazardous waste, or impacts areas of historical/ critical concern
EFSB	Approval to construct	Siting	- Size > 100 MW - Includes new transmission lines in a right of way 69 kV or more and > 1 mile or 115 kV or more and > 10 miles
DEP Air Program Planning Unit	Air Plans Approval	Air Quality	- Heat rating input of > 3 million Btu/hour
DEP Air Program Planning Unit	Air Plans Approval	Noise Impacts	- For facilities that operate on a 4-hour per day minimum basis
DEP Water Pollution Program	Water Quality Certification	Wastewater Discharge	- Dredging, filling, or construction of intake or discharge structure in surface or groundwater
DEP Drinking Water Program	Water Withdrawal Permits	Present and Future Water Use	- Withdrawal in excess of 100,000 gallons/ day
DEP Wetlands and Waterways Program	Chapter 91 License	Wetland and Waterway Development and Use	- Any alteration to bank, riverfront, freshwater or coastal wetland, beach, dune, flat, marsh, meadow or swamp bordering ocean, freshwater, or land subject to tidal action
DEP Business Compliance Division	Site Assignment from Bd. of Health and DEP Operating Permit	Solid Waste Management	- Use of refuse, waste wood, or other solid wastes as fuel for generating power and thermal energy
DEP Waste Programs Planning Unit	Hazardous Waste Permit	Handling of Hazardous Waste	- Hazardous waste production (excludes waste generated primarily from the combustion of coal or other fossil fuels)
EOEA Div. of Coastal Zone Management	CZM Consistency Review	Coastal Zone Development and Use	- Project development is on or outside the coastal zone, affects land/water use in the coastal zone, requires a federal permit, or is federally funded.
DFW MA Natural Heritage Program	Conservation Permit	Preservation of Rare Species or Habitat	- Significant alteration of rare habitat or potential impact upon endangered species.
Local			
MA Solar Access Law	Solar Access Permits	Protection of Solar Access	- Applicable to eligible solar technologies if community passes law
Building Inspector	Building Permits	Building Permits MA Building Code Local Zoning Laws	

(Zoning) Board of Appeals	Special Permits	Variances Special Permits Review of Building Inspector Determinations	
Electrical Inspector	Electrical Inspection	MA Electrical Code	
Plumbing Inspector	Plumbing Inspection	Plumbing Provisions of MA fuel, gas, and plumbing code	
Gas Inspector	Gas Inspection	Gas Provisions of MA fuel, gas, and plumbing code	
Planning Board	Siting Approval	Site Plan Approval (Bd. of Selectmen in some towns)	
Conservation Commission	Conservation Approval or Permits	Wetlands, floodplain, soil erosion, and runoff	
Water/Sewer Commission	Water Supply and Quality Permits	Protection/adequacy of local water supply and quality Sewer extension and connection	
Fire Inspector	Fuel Storage Approval		- Oil tank storage - Ammonia storage
Historical Commission	Commission Approval		- Modifications to sites with historical significance
Department of Public Works	Permits for Curb Cuts/ Service Roads		- Need for curb cuts or service roads
Town/ City Engineer	Engineering Permits		- Need for grading - Impact on highway/ traffic
Bd. of Public Health	Permits/ Approval	Public Health Issues	- Air quality impact, hazardous waste impacts, etc.
Section 5.0: Distribution and Transmission Interconnection and Metering Issues			
ISO			
ISO	System Impact Study	Effects of Interconnection on Reliability	- For facilities of size >5 MW wishing to interconnect directly to the ISO
	Facilities Study	Assess Need for a Transmission Modification	- Need determined by outcome of System Impact Study
Distribution Company			
MA DTE (standards pending)	Written Certification from Qualified Personnel	Safety Standards and Requirements	- NFPA, IEEE, and UL provide safety guidelines
	Written Notice of Intent to Interconnect	Interconnection Procedure	- Required for facilities wanting to interconnect with distribution company

Appendix Five: Relevant Policies

Title	Acronym	Statute	Regulation	Regulatory Agency	Web location	Description
State						
Coastal Wetlands Restoration Act		M.G.L. c. 130, ss. 105			http://www.state.ma.us/legis/laws/mgl/index.htm	allows for the restriction of activities that alter or pollute coastal wetlands
Coastal Zone Management Act of 1972		M.G.L. c. 21A, ss. 1-15		EOEA Division of Coastal Zone Management	http://www.state.ma.us/legis/laws/mgl/index.htm	gives coastal states the funding and opportunity to manage coastal resources+G15
Hazardous Waste Regulations			310 C.M.R. 30	DEP Waste Programs Planning Unit	www.state.ma.us/dep/bwp/dhm/dhmpubs.htm#regs	contains the requirements for the generation, storage, collection, transport, treatment, disposal, use, reuse, and recycling of hazardous waste
Inlands Wetlands Restriction Act		M.G.L. c. 130, ss. 105			http://www.state.ma.us/legis/laws/mgl/index.htm	orders the protection of inland wetlands
Massachusetts Clean Waters Act		M.G.L. c. 21, ss. 26-53		DEP Water Pollution Control Program	http://www.state.ma.us/legis/laws/mgl/index.htm	to enhance the quality and value of water resources and to establish a program for control, prevention, and abatement of water pollution, controls the uses of water in Massachusetts
Massachusetts Environmental Policy Act	MEPA	M.G.L. c. 30, ss. 61-62H	310 C.M.R. 11	DEP	http://www.state.ma.us/mepa/301-11tc.htm	requires agencies to determine the impact on the natural environment of all projects and activities
Massachusetts Solar Access Law		M.G.L. c. 40A, ss. 1A, 3, 9B; M.G.L. c. 41, ss. 81Q			http://www.state.ma.us/legis/laws/mgl/index.htm	allows solar easements to protect solar exposure and authorzes zoning rules that prohibit infringements on solar access

Massachusetts Water Management Act		M.G.L. c. 21G		DEP Drinking Water Program	http://www.state.ma.us/legis/laws/mgl/index.htm	provides for the planning, establishment, and management of programs to assess the uses of water in Massachusetts and plan for future water needs
MHC State Review and Compliance		M.G.L. c. 9, ss. 26-27C	950 C.M.R. 71	MHC	www.state.ma.us/legis/laws/mgl/index.htm	to identify , evaluate, and protect the Commonwealth's important archaeological and historic resources
Public Waterfront Act		M.G.L. c. 91			http://www.state.ma.us/legis/laws/mgl/index.htm	designed to protect public rights in Massachusetts waterways
Rules Governing the Restructuring of the Electric Industry			220 C.M.R. 11.00		http://www.magnet.state.ma.us/dpu/restruct/competition/index.htm	provides regulatory framework for the restructured electric industry
Solid Waste Management Act		M.G.L. c. 111, ss. 150A	310 C.M.R. 16	DEP Waste Programs Planning Unit	http://www.state.ma.us/legis/laws/mgl/index.htm	regulates the handling and disposal of solid waste in Massachusetts
Water Quality Certification Program		M.G.L. c. 131, ss. 40A			www.state.ma.us/dep/brp/wm/wmpubs.htm#regs	establishes procedures and criteria for the discharge of dredged or fill material, dredging, and dredged material disposal in waters of the US within the Commonwealth
Wetlands Protection Act		M.G.L. c. 131, ss. 40	310 C.M.R. 10	DEP Wetlands and Waterways Program	http://www.state.ma.us/legis/laws/mgl/index.htm	establishes the guidelines for protecting and preserving wetlands and the principles for obtaining a permit to alter them
Federal						
Clean Water Act		33 U.S.C. 1251 et.seq		U.S. Environmental Protection Agency	http://www.epa.gov/epahome/laws.htm	sets the Federal standards for water pollution; delegates mostly to states
Energy Policy Act of 1992	EPAct	Pub.L. 102-486			http://thomas/loc/gov	allows for a new type of electricity producer called the EWG

Federal Power Act of 1935	FPA	16 U.S.C. 792 et seq.			http://thomas/loc/gov	gives the FERC regulatory authority over wholesale electricity markets
Flood Disaster Protection Act of 1973		42 U.S.C. 5121 et seq.		FEMA	http://www4.law.cornell.edu/uscode/#SECTIONS	identifies special flood hazard areas and provides measures of assistance to alleviate damage from disaster
Marine Protection Research and Sanctuaries Act		16 U.S.C. et seq., 1447 et.seq., 33 U.S.C. 1401 et seq., 2801 et seq.		U.S. Army Corps of Engineers	http://www4.law.cornell.edu/uscode/#SECTIONS	authorizes the COE to regulate the transportation of dredged material for the purpose of disposal in the ocean
National Electric Code	NEC	42 U.S.C. 8484		NFPA	http://www4.law.cornell.edu/uscode/#SECTIONS	code for electrical equipment and wiring safety in buildings
National Environmental Policy Act	NEPA	42 U.S.C. 4321-4347		U.S. Council on Environmental Quality	http://www.epa.gov/epahome/laws.htm	the basis of all environmental protection in the US: it establishes policy, sets goals, and provides means for carrying out the policy
National Historic Preservation Act			36 C.F.R. 800	MHC	http://thomas/loc/gov	delegates most authority to the states
Public Utility Holding Company Act of 1935	PUHCA	15 U.S.C. 79 et seq.		FERC, DTE in MA	http://thomas/loc/gov	establishes the framework for the traditional regulated electric industry
Public Utility Regulatory Policies Act of 1978	PURPA	16 U.S.C. 2601 et seq.		FERC, DTE in MA	http://thomas/loc/gov	facilitates the development of markets for renewable electricity generation
Resource Conservation and Recovery Program	RCRA	42 U.S.C. 6901 et seq.		EPA	http://www.epa.gov/epahome/laws.htm	allows the EPA to control all stages of hazardous waste
Rivers and Harbors Act of 1899		33 U.S.C. 401 et seq.		COE	http://www4.law.cornell.edu/uscode/#SECTIONS	outlines laws for constructing any bridge, causeway, dam, or dike over or in any navigable water of the US

Appendix Six: Resources

Name	Agency	Internet Location
A New Organizational Structure	ISO-NE	http://www.ISO.com/about_the_iso/organizational_structure.html
Application for NEPOOL Transmission Services	NEPOOL	http://www.ne-iso.com
Application for Proposed Construction	FAA	http://www.faa.gov/ats/ata/ata400/7460-1f.doc
Coastal Zone Territories	MCZM	http://www.magnet.state.ma.us/czm/fcrproc.htm
DEP Permitting: A Catalog and User's Manual	DEP	http://www.state.ma.us/dep/files/permits/intromg.htm
DOER's Consumer Education Site	DOER	http://www.magnet.state.ma.us/thepower
Environmental Monitor	MEPA	http://www.state.ma.us/mepa/301-11tc.htm
FERC Tariff For Transmission Dispatch and Power Administration Services	ISO-NE	http://www.iso-ne.com
Financial Incentives for a Business to Invest in Renewable Energy Systems. Energy Efficiency and Renewable Energy Network Reference Briefs	DOE	http://www.eren.doe.gov/consumerinfor/refbriefs/la7.html
How to Obtain Qualifying Status for Your Facility	FERC	http://www.ferc.fed.us/electric/qinfo/Qfhow.htm
Massachusetts Renewable Energy Tax Credits	DOER	http://www.magnet.state.ma.us/doer/programs/renew/renew.htm
Noise pollution policy	DEP	http://www.state.ma.us/dep/energy/noispol.htm
Procedures for the Establishment and Study of NEPOOL Interconnection	ISO-NE	http://www.iso-ne.com
Review Thresholds	MEPA	http://www.state.ma.us/mepa/301_1103.htm
Summary of The Department's Electric Industry Restructuring Rulemaking Proceedings	MA DTE	http://www.magnet.state.ma.us/dpu/restruct/competition/index.htm
The Siting of Energy Facilities in the Commonwealth of Massachusetts	EFSB	http://www.state.ma.us/dpu/siting_board.htm

Appendix Seven: Sample Projects

Project	Description	Contact
Beverly - Wind	Since 1997, the City of Beverly has benefited from the wind turbine installed at Beverly High School and run by Solar Now, Inc. Donated to a group of Beverly fifth graders in 1995, the turbine helped enhance the educational value of the site, which already included a solar array. The original turbine was recently replaced with a similar model to the one donated by DOER. The turbine has a maximum output of 10 kilowatts. The wind turbine and solar array save Beverly an average of $10,500 per year on its electric bill. The wind turbine is also part of Solar Now's educational activities which include tours given to students, citizens, and others interested in renewable energy.	Solar Now; (978) 927-9786x 205; solar19@idt.net
Braintree – Fuel Cell/ Landfill Gas	The DOER awarded the Braintree Electric Light Department a $100,000 grant to help fund its new fuel cell demonstration project. Located at the now-closed Town of Braintree landfill, the fuel cell began operation this past summer. It generates enough electricity to meet the average electric needs of approximately 75 households. The Braintree fuel cell helps to reduce air pollution by capturing the methane gas that is naturally produced by decay in the landfill and using it to generate electricity. This process helps reduce the amount of greenhouse gases that escape into the air and would otherwise contribute to global warming.	Braintree Electric Light Department (781) 348-2353
Cambridge - PV	PV panels mounted on the rooftops of stores at Porter Square Shopping Center produce 40,000 kWh of electricity per year, providing one-third of the energy needed to run the 160,000-square-foot center's common areas. The approximately $500,000 invested in the solar energy system will reduce electric bills - a draw for tenants. Gravestar, the project developer, highlights community input as integral to the project's ongoing success. Both Cambridge and Somerville neighborhood groups were involved from the beginning.	Paul Lyons, Zapotec Energy; (617) 868-1964; Lyons@zapotecenergy.com
Chelmsford, Lynn, and West Newbury - PV	In 1997, three schools in Massachusetts, were chosen to host PV systems as part of a program to combine learning opportunities for local students and the electric utility, New England Electric. Through the program, students learn about renewable energy, while the utility monitors system performance to test the feasibility of utilizing PV in its energy mix. Two of the schools, Pickering Junior High (Lynn) and Pentucket Regional High School (West Newbury), received 4 kW roof-mounted PV systems; the McCarthy Middle School (Chelmsford) received a 2 kW system. Electricity generated by the PV is not used directly by the schools, but feeds into Massachusetts Electric's power grid. All three systems use ASE Americas modules and Trace inverters. Cost-sharing for all of the projects mentioned above is provided by the UPVG's Round Two TEAM-UP program as part of the Ascension Technology Inc., venture.	Utility PhotoVoltaic Group; www.upvg.org/upvg/index.htm; (202) 857-0898; upvg@ttcorp.com

Gardner—Solar	Several years ago, Massachusetts Electric installed solar systems into a number of homes in Gardner. Its program provided a successful model for how such systems could be successfully interconnected into the grid.	http://solstice.crest.org/renewables/SJ/pv/293.html
Hull - Wind	The Town of Hull occupies a narrow strip of land that nearly reaches the middle of Boston Harbor. Surrounded by water, Hull is quite windy. In 1984, the Hull School Department received a grant from the DOER to install of a wind turbine at the local high school. The Enertech 40 kW wind turbine began operation in the spring of 1985. The turbine produced over 80,000 kWhs in 1995, saving the school department over $8,500 off its electricity bill. The town is actively looking to replace the old turbine with a new one.	Hull Municipal Lighting Plant; 781-925-0051
Mount Tom -Wind	The largest operating wind turbine in Massachusetts sits atop Mount Tom in Holyoke. The 250 kilowatt turbine is owned by the University of Massachusetts and is used for research and education. The University's Renewable Energy Research Laboratory (RERL) acquired the turbine from a California wind farm. The turbine received a complete overhaul and was modified for cold weather operation before its installation in late 1994. The RERL is conducting ongoing research on both the turbine components and the automated turbine control systems.	Jim Manwell, Director, UMass RERL; (413) 545-4359
North Attleboro – Landfill Gas	AllEnergy has a commitment to purchase power from a 1600 kW landfill gas project operated by Highland Power at the North Attleboro landfill. The project uses methane produced by decomposing landfill garbage to produce electricity. The project would produce approximately 13.3 million kWh of electricity per year.	John Steward, Highland Power; (508) 697-3342
North Dartmouth - PV	Through AllEnergy's partnership with the Conservation Services Group and their Sunpower Electric program, commitments have been made to develop PV. The first PV installation occurred in November 1998 at a host site on BJ's Wholesale Club building in North Dartmouth. The 15 kW PV system consists of 52 solar panels manufactured by ASE Americas, Inc. of Billerica, MA and four solar panels of Evergreen of Waltham, MA. The PV system produces approximately19,500 kWh per year. BJ's Wholesale Club has donated its roof space to help generate this green energy. There are plans to develop additional solar facilities with BJ's Club across Massachusetts.	Jennifer Wylde, Conservation Services Group; (508) 836-9500; jennifer.wylde@csgrp.com
Princeton - Wind	Princeton Light Department operates the oldest windpower plant in Massachusetts. Located in central Massachusetts, Princeton installed eight Enertech wind turbines in 1984 on a hilltop near Mt. Wachusett. Each turbine has a rated power of 40 kilowatts and sits atop an 80 foot tower. The entire facility produces approximately 250,000 kWh per year - enough to supply the annual energy needs of over 40 households. In fifteen years of operation, the windpower plant has displaced the use of thousands of gallons of fuel oil and has avoided hundreds of tons of carbon dioxide emissions.	Princeton Municipal Light Department (978) 464-2815; www.pmld.com