Assessing the Impact of Offshore Wind in Massachusetts: An Estimate of $C0_2$ Emissions Reductions

A thesis submitted by

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Abstract

Massachusetts' Act to Promote Energy Diversity requires distribution companies to solicit contracts for up to 1600 MW of offshore wind. To test whether offshore wind projects can meet the Act's requirement to reduce $C0_2$ emissions, the Oak Ridge Competitive Electricity Dispatch Model was used to forecast changes in ISO New England's resource mix under five different wind capacity levels and calculate avoided $C0_2$ emissions attributable to offshore wind. With 1600 MW of installed capacity, representing full solicitation under the Act, reliance on natural gas is reduced by ~10% and carbon emissions decline by ~9%. This represents significant progress towards the goals of the Global Warming Solutions Act and the Clean Power Plan. The 5000 MW scenario reduces emissions enough to meet the Clean Power Plan's 2030 goals. This study's application of a dispatch model provides an example for policymakers of a simple and cost-effective approach for assessing a project's value.

Table of Contents

Abstract ..... **ii**

List of Tables ..... **v**

List of Figures ..... **vi**

Chapter 1: Introduction **2**

Research Question 4

Chapter 2: Background **5**

Offshore Wind Focus Area 5

Wholesale Electricity Markets 6

The Need for Offshore Wind: 9

Offshore Wind Policy Environment 16

Chapter 3: Literature Review **23**

Basics Of Offshore Wind 23

Economics of Offshore Wind 27

Economic Development Impacts 33

Electrical System Impacts 35

Greenhouse Gas Emissions Literature 37

Chapter 4: Methods and Model Design **41**

Data Sources 41

Oak Ridge Competitive Electricity Dispatch Model 50

Modeled Offshore Wind Scenarios 60

Chapter 5: Results/Discussion **61**

Dispatch Model Validation 61

Validation Summary 66

Model Results 66

Chapter 6: Analysis 76

Findings in Context 76

The Act to Promote Energy Diversity: Revisited 78

Clean Power Plan 86

Chapter 7: Conclusion & Recommendations 88

Works Cited 90

List of Tables

Table 1: Offshore Wind Cost Components 29

Table 2: NEMS Variables 42

Table 3: Wind TOOLKIT Outputs 47

Table 4: Fuel Carbon Emissions Factors 59

Table 5: Resource Mix Validation 62

Table 6: Historical Ranges of ISO New England Resource Mix 63

Table 7: ORCED Fossil Fuel Generation 64

Table 8: Emissions Calculation Correction 65

Table 9: Value of Avoided Emissions per MWh 82

Table 10: Range of Values from Social Cost of Carbon 83

List of Figures

Figure 1: BOEM Offshore Wind Leasing Areas in Massachusetts 6

Figure 2: GHG Emission Pathways 11

Figure 3: RSLR at Boston 12

Figure 4: Temperature Change in Boston 12

Figure 5: Precipitation Intensity 13

Figure 6: Fossil Fuel Prices (2005-2015) 43

Figure 7: AEO Fuel Price Forecast ($/MMBtu) 44

Figure 8: ISO New England vs. FERC Form 714 Demand 45

Figure 9: 2015 Hourly System Load 46

Figure 10: Wind TOOLKIT Site 48

Figure 11: ORCED Model Design 51

Figure 12: ORCED Modules 52

Figure 13: 2015 ISO New England LDC 54

Figure 14: Winter LDC vs. Winter with Wind LDC 55

Figure 15: Hydro LDC 57

Figure 16: ORCED Dispatch Showing Plant Production 58

Figure 17: 2026 Modeled Weekly Demand 67

Figure 18: January and July Wind Production 68

Figure 19: January and July Average Demand Curves 69

Figure 20: Winter LDC and Winter LDC net of Wind Production 70

Figure 21: Summer LDC and Summer LDC net of Wind Production 70

Figure 22: Total Electricity Generation 71

Figure 23: Change in Electric Generation 72

Figure 24: CO_2 Emissions 73

Figure 25: CO_2 Emissions Rate 74

Figure 26: Avoided Emissions per MWh of Offshore Wind Production 74

Figure 27: ISO New England Gas and Electricity Prices 81

Figure 28: SCC Distribution from Technical Update of the SCC for Regulatory Impact Analysis 84

Figure 29: Costs and Benefits of Offshore Wind 86

Figure 30: Massachusetts CO_2 Emissions Reductions 87

Assessing the Impact of Offshore Wind in Massachusetts:

An Estimate of $C0_2$ Emissions Reductions

Chapter 1: Introduction

Massachusetts is taking a bold step to support the development of its offshore wind resource with The Act to Promote Energy Diversity (*An Act to Promote Energy Diversity* 2016), which provides a process for offshore wind developers to connect to the bulk electricity system in Massachusetts and sell power to ratepayers. One of the primary stated goals of the program is to reduce carbon emissions from the electricity-generating sector, which will help the state achieve required reductions under the United States Environmental Protection Agency's (USEPA) Clean Power Plan and the state's Global Warming Solutions Act ("Clean Power Plan: State at a Glance Massachusetts" 2016, *An Act Establishing the Global Warming Solutions Act* 2017). This move to reduce carbon emissions in the state is driven by an existential risk posed to the state from rising sea levels, which threaten Boston and other communities along the coast, rising temperatures, which pose risks to public health and our built and natural infrastructure, and increased precipitation rates, which could lead to more frequent and severe inland flooding events. All together, this Act provides another option for the state to reduce emissions from the power sector, and takes advantage of the unique offshore wind resource possessed by Massachusetts.

To secure contracts under the Act, Offshore wind developers must demonstrate that their projects will reduce emissions, increase reliability, and reduce winter price spikes. Several methods exist to measure the avoided emissions resulting from offshore winds, including measuring current emissions rates, applying econometric methods, and utilizing models that simulate grid operations (dispatch models), but they vary in cost and complexity. This thesis forecasts the potential avoided emissions from offshore wind using a dispatch model, then compares these findings

against other methods to provide some insight into the effectiveness of each. In reviewing the cost-effectiveness of any offshore wind farm, regulators and policy makers will need to apply some method for measuring these reductions. Econometric models are useful for reviewing the present day impacts of a resource on emissions, but it can be hard to apply their findings to structural changes in the resource mix of a region, which the Act to Promote Energy Diversity may force on the system. The simplest method of just measuring the emissions of the marginal unit and then counting that as the avoided emissions from a wind farm also misses the potential for offshore wind to radically alter the grid's resource mix, both in what is displaced, and what is needed to balance the intermittency of wind. Dispatch models can handle structural changes, and are good at accounting for the increased variability of wind resources, although their cost and complexity can make them difficult to apply. This thesis provides an example of a relatively simple and cost-effective dispatch model that can be used to calculate the avoided emissions from a renewable energy resource.

In addition to predicting the avoided emissions, a successful project in Massachusetts will also positively impact the state's economy and provide employment for its workers. This thesis provides a review of the relevant literature, both gray and academic, to provide readers with a foundational understanding of the potential impacts from offshore wind. Primarily, research from the National Renewable Energy Laboratory and industry reports from the more mature offshore wind industry in Europe are used to gain visibility into what the impacts might be in Massachusetts.

The final consideration reviewed in this study is whether offshore wind is likely to impact electricity reliability in Massachusetts. This is accomplished through another literature review, and by evaluating the resource mix impacts of offshore wind in ISO New England using the aforementioned dispatch model. All together, these methods provide a foundation for those interested in researching the impacts of offshore wind.

Research Question

The guiding question for this study is whether offshore wind projects in Massachusetts will achieve the goals of The Act to Promote Energy Diversity. This is broken down into three component questions:

1. Will offshore wind projects reduce CO_2 emissions?
2. Will there be economic benefits to the state from an offshore wind project?
3. Will an offshore wind project increase electricity reliability and reduce winter wholesale power prices?

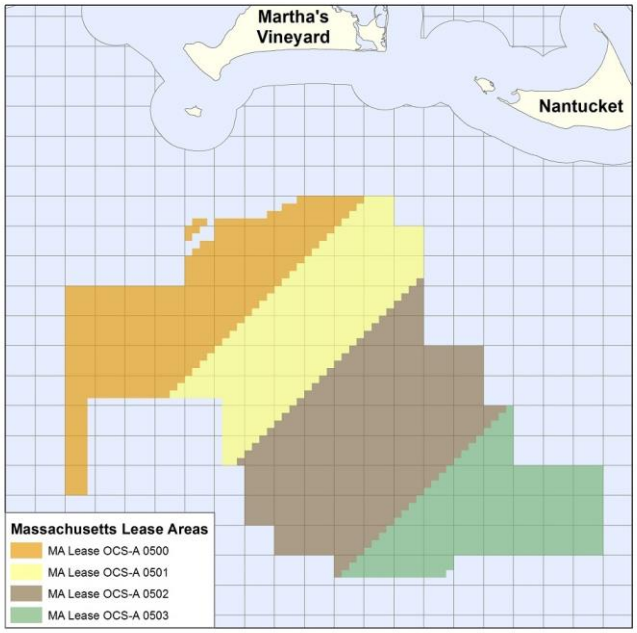
This thesis analyzes these questions by reviewing literature on the economic benefits of offshore wind, the costs and economic benefits of offshore wind projects, and the emissions impacts of offshore wind in other regions. The answers revealed through the literature are supplemented and aided through the application of the Oak Ridge Competitive Electricity Dispatch Model, which allows this thesis to systematically test how different offshore wind capacity levels will impact the grid in the chosen forecast year, 2026.

Chapter 2: Background

Offshore Wind Focus Area

This thesis focuses on the impact of offshore wind on carbon emissions in Massachusetts, and ISO New England more broadly. Offshore wind is defined by the Massachusetts Legislature in An Act to Promote Energy Diversity as electricity generation "derived from wind that: 1) are Class I renewable energy generating sources… 2) have a commercial operation on or after January 1, 2018, that has been verified by the Department of Energy Resources; and 3) operate in a designated wind energy area for which an initial federal lease was issued on a competitive basis after January 1, 2012" (*An Act to Promote Energy Diversity* 2016). In 2010, The Bureau of Ocean Energy Management identified 826,241 acres south of Cape Cod and the Islands for Offshore Wind development, with 742,000 acres being put up for auction in 2014. Two commercial developers, DONG Energy and RES America won the leases to lease area 0500 and lease area 0501 in January 2015 (Figure 1). This thesis focuses on the effect on carbon emissions of a full build-out of these resources by 2026 (BOEM 2017).

Figure 1: BOEM Offshore Wind Leasing Areas in Massachusetts



Source: (BOEM 2017)

Wholesale Electricity Markets

To understand the results of this thesis, it is necessary to understand that electricity in New England and Massachusetts is bought and sold in a marketplace. This is a fundamental shift from how electricity was procured in the past, when vertically integrated monopolies controlled the generation, transmission, and distribution of electricity to customers. In the old model, state legislators granted electric utilities monopoly power in order to reduce duplicate infrastructure investments; a so called natural monopoly. In exchange for their monopoly power, the utilities agreed to regulatory oversight; in Massachusetts, the Department of Public Utilities took on this role. For a utility to increase electricity rates, they needed to justify the increase by pointing to necessary infrastructure improvements like new transmission lines, new generation plants constructed to meet growing demand, and new distribution

infrastructure. The rates were based on the cost of delivered service with an agreed on margin to provide a return on invested capital (Troesken 2006).

Beginning in the 1970s with the passage of the Public Utility Regulatory Policies Act of 1978 (PURPA), the power sector moved towards deregulated markets. With PURPA, independent power producers were given the opportunity to produce electricity for customers, using the utility's distribution system to deliver the electricity ("Public Utility Regulatory Policies Act of 1978 (PURPA) | Department of Energy" 2017). Following this, the federal government relaxed regulations governing generators further with the Energy Policy Act of 1992, which created new incentives for renewable energy, challenged utilities to encourage energy efficiency measures instead of just increasing capacity, removed constraints on non-utility generation, and opened up the transmission system on a case by case basis to non-utility generators ("Energy Policy Act of 1992" 2017). Full deregulation occurred with the Federal Energy Regulatory Commission's Order 888 and Order 889, which opened up the transmission system to competitive generation and allowed for the wholesale trade of electricity ("Our History" 2017). Massachusetts deregulated its own electric utilities in 1997 when the legislature passed a law that eliminated the monopoly electric utility model and allowed consumers to purchase electricity directly from producers (*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.* 1997).

In New England, this led to the creation of ISO New England, an independent system operator (ISO) that is charged with operating the bulk electricity system, conducting long-term system planning, and administering the wholesale electricity markets.

Today, ISO New England operates multiple markets that allow for competition in every facet of the bulk electricity system. For longer term planning, ISO New England operates a forward capacity market that procures electricity for future years, and provides payments to generators who are able to provide capacity when called upon.

ISO New England also operates the day-ahead and real-time electricity markets, which is where the economic dispatch of generation occurs. In both markets, competitive electricity suppliers (e.g., Eversource) that provide electricity directly to customers through the distribution system enter in a demand bid. At the same time, generators offer hourly supply bids that reflect their marginal cost of energy production (akin to their variable costs). For fossil fuel generators, the marginal cost is primarily comprised of fuel costs, operations and maintenance costs, and capital costs. Conversely, for a wind operator, there is almost no marginal cost to provide energy; almost all of the costs are derived from the initial capital costs. Once bids are in for each hour of the day, ISO New England runs a linear optimization problem with the objective to minimize the wholesale cost of electricity while meeting demand and reserve requirements (Burke 2011). This economic dispatch approach is replicated in this thesis using the Oak Ridge Competitive Electric Dispatch Model (ORCED).

The third market administered by ISO New England is the ancillary services market, which is where additional services like system regulation and voltage support are traded (Burke 2011). This market is not replicated in the ORCED model, and is outside of the scope of this thesis.

Offshore wind serves as a source of generation and would typically offer their capacity into the wholesale electricity markets operated by ISO New England. The Act to Promote Energy Diversity passed by the Massachusetts legislature requires that any offshore wind electricity be sold through a bi-lateral agreement between a competitive electricity supplier and the independent power producer that owns and operates the offshore wind farm (e.g., DONG Energy) (*An Act to Promote Energy Diversity* 2016). Instead of operating in the wholesale electricity markets, the energy is traded outside of the market through a power purchase agreement. The effect of this structure is that a supplier like Eversource will reduce their demand bids into the market by whatever amount is provided by the offshore wind farm. In other words, instead of procuring energy in a market, they are purchasing it directly from a generator. This has the effect of reducing demand for energy in the wholesale markets, potentially depressing energy prices ("Integrating Markets and Public Policy: Policies and Markets Problem Statement" 2016). This impact is discussed in more detail later in the thesis.

The Need for Offshore Wind:
Energy Independence

In addition to mitigating the effects of climate change by reducing carbon emissions, Massachusetts is taking steps to become more energy independent by reducing its reliance on imported fuels for electricity generation. Instead of piping or shipping in fuel, Massachusetts can develop and take advantage of renewable resources available locally. Every year, Massachusetts consumes ~$24 billion worth of energy, with the majority, around $18 billion, being sent out of the state to pay for energy imports (Sylvia 2011; Energy Information Administration 2017b). The state also lacks any significant fossil fuel industry, with no refineries and no crude or natural

gas production (Breslow et al. 2014, 89). On a per capita basis, this represents an expenditure of about $5,200, with $1,300 going to electricity generation, and almost all leaving the state (MA Executive Office of Energy and Environmental Affairs 2015). The creation of an offshore wind industry, which has the potential to provide enough power to allow the state to export energy, would generate income and reduce this enormous transfer of wealth out of Massachusetts.

Threat of Climate Change

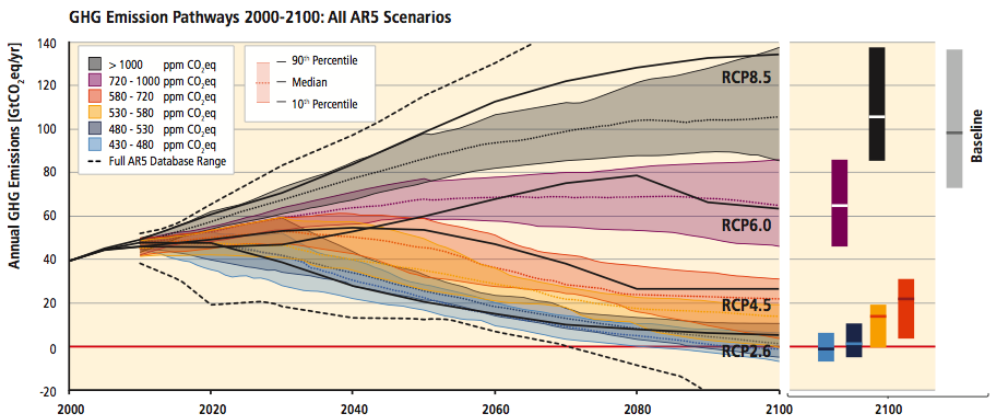
The latest climate change scenarios for the 2050s in Massachusetts predict a 7-degree increase in average temperatures, 18" of sea level rise, and an increase in the intensity of extreme precipitation events ("Climate Ready Boston: Climate Change and Sea Level Rise Projections for Boston" 2016) if we continue on the emissions trajectory we are currently on. Because of emissions already emitted into the atmosphere, we know we will see some of these effects by 2030, but beyond 2030, the effects are largely dependent on our actions. The potential pathways for climate change are described in the Intergovernmental Panel on Climate Change (IPCC) Fifth Assessment Report (AR5) as "representative concentration pathways", or RCPs. In IPCC's AR5 report, they model three RCP scenarios for climate change (Field, Barros, and Dokken 2014):

1. RCP 2.6: The low emissions scenario; $C0_2$ emissions are reduced to one-third of their current values by 2050, and are zero by 2080. $C0_2$ concentrations never exceed 450 ppm in this scenario. This is the target of the Paris Climate Conference (COP21) because it keeps warming below 2 degrees Celsius and avoids the worst consequences of global warming.

2. RCP 4.5: $C0_2$ levels remain at their current levels through 2050, and then slowly decline. $C0_2$ concentrations reach 540 ppm in 2100. Global temperatures increase by 1.9-3.3 degrees Celsius.
3. RCP 8.5: The highest emissions scenario represents climate change impacts if fossil fuels continue to drive economic growth, much like they have for the last two centuries. $C0_2$ concentrations increase by 250%, to 940 ppm by 2100 in this scenario. Global temperatures increase by 3.3-5.5 degrees Celsius.

The differences between the scenarios and their associated $C0_2$ emissions levels are apparent in Figure 2.

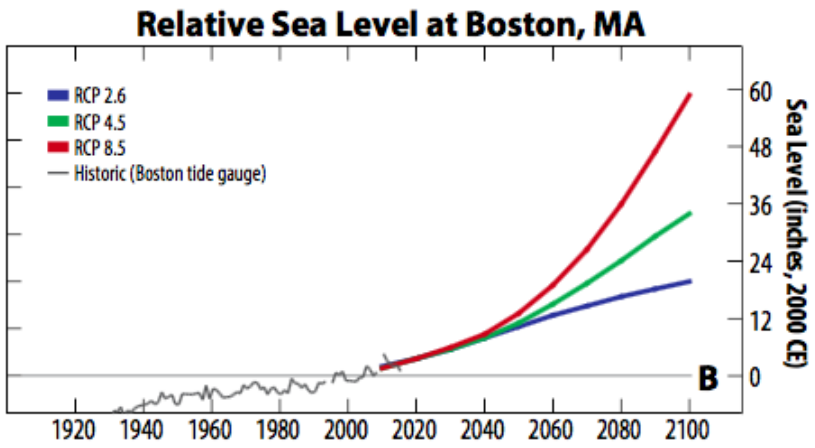
Figure 2: GHG Emission Pathways



Source: (Edenhofer et al. 2014)

To understand the local implications of each of these pathways, communities like the City of Boston have downscaled these projections. Figures 3 through 5 visualize the range of impacts that the Boston region can expect in each of the different scenarios (Boston Research Advisory Council 2016). Sea level rise by 2030 varies little across the three scenarios, but by 2070, there is a wide divergence in the pathways.

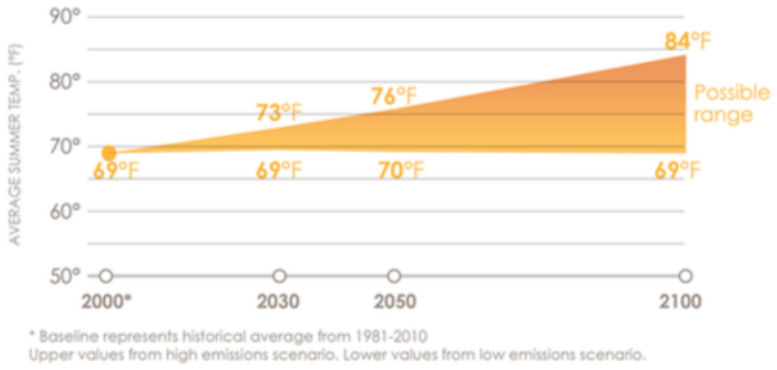
Figure 3: RSLR at Boston



Source: (Boston Research Advisory Council 2016)

In the low emissions scenario, Boston will experience about 20" of sea level rise; in the high emissions scenario, Boston will experience about 26.4" of sea level rise. This difference is exaggerated in 2100, with the high scenario projected to cause 58" of sea level rise, which is about 1.75x the sea level rise expected in the low emissions scenario.

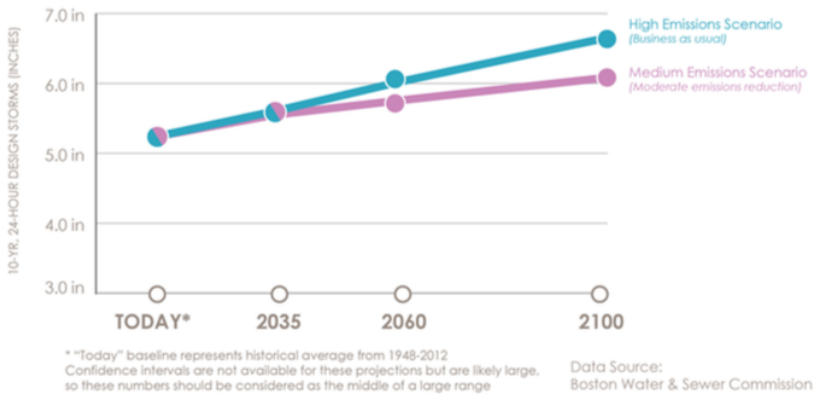
Figure 4: Temperature Change in Boston



Source: (Boston Research Advisory Council 2016)

For temperatures, there is a 4 degree Fahrenheit difference in 2030 in average summer temperature, but by 2100, summers are projected to be almost 15 degrees warmer on average in the high scenario compared with the low emissions scenario.

Figure 5: Precipitation Intensity



Source: (Boston Research Advisory Council 2016)

Finally, for precipitation intensity, which can lead to more extreme inland flooding events, the Boston Research Advisory Group report projects no difference between scenarios in 2035, but by 2100, the 24 hour precipitation event will be 10% greater in the high emissions scenario compared with the medium emissions scenario ("Climate Ready Boston: Climate Change and Sea Level Rise Projections for Boston" 2016).

If the lower emissions scenarios are not pursued, storm surges and sea level rises pose a significant threat to infrastructure in Massachusetts. Boston, with help from the Massachusetts Department of Transportation and the City of Cambridge, developed the Boston Harbor Flood Risk Model to probabilistically model the depth and probability of flooding from sea level rise and storm surges that might occur in 9" and 36" sea level rise (SLR) scenarios. In all scenarios, 9" of SLR is expected to

occur around 2050. 36" of sea level rise is predicted to occur between 2070 and 2100 in both the medium and high scenarios, but it will never occur in the low emissions scenario. Their modeling predicts that for a 1% annual chance storm, 8% of Boston will experience flood impacts. This increases to 18% of Boston with 36" of SLR. With this much SLR, 8% of the city will experience flooding at the monthly high tide (Boston Research Advisory Council 2016).

Climate Change Policies

Only if steps are taken by national governments to achieve the goals of the Paris Climate Agreement will we avoid the worst consequences of climate change by keeping temperatures less than 2 degrees Celsius higher than pre-industrial temperatures (Field, Barros, and Dokken 2014). To reach this goal in the United States, the USEPA enacted the Clean Power Plan rule, which regulates carbon emissions from electric generating units under the authority of the section 111(d) of the Clean Air Act (*Clean Power Plan*, n.d.). With a new U.S. presidential administration that is less supportive, the future of the Clean Power Plan is uncertain, but its reduction goals are a useful benchmark for emissions reductions at the state level. Fossil-fueled power plants emit 31% of total U.S. greenhouse gas emissions (US EPA 2015). To reduce this amount, the Clean Power Plan calls for a 32% reduction below 2005 levels in carbon emissions from power plants. The Clean Power Plan achieves this goal through three building blocks:

1. Improve energy efficiency of existing power plants
2. Replace generation from coal power plants with generation from cleaner natural gas power plants

3. Substitute generation from zero emitting generation sources for fossil fuel sources

These building blocks are coupled with yearly targets set for each state based on their share of national carbon emissions. Each year from 2020 to 2029, the states must achieve either a mass reduction (tons of $C0_2$) or a rate based reduction (tons/MWh of generation) that steps down gradually year over year (*Clean Power Plan*, n.d.). Under the plan, Massachusetts' 2012 mass baseline was set by the EPA at 13,125,248 short tons of $C0_2$ emissions, with a 2030 emissions target of 12,104,747 short tons of $C0_2$ emissions ("Clean Power Plan: State at a Glance Massachusetts" 2016).

Additionally, Massachusetts set statewide goals for carbon emissions reductions under the Global Warming Solutions Act of 2008 that mandates an 80% reduction in emissions below 1990 levels (*An Act Establishing the Global Warming Solutions Act* 2017). 1990 emissions for electricity generated in Massachusetts were 25.1 MMTCO2e; to achieve an 80% reduction Massachusetts will need to reduce its emissions to 5.02 MMTCO2e. This represents a more than 50% reduction from current levels.

To achieve the goals of the Global Warming Solutions Act, Massachusetts proposed the following reductions for the electricity generation and distribution sectors (MA Executive Office of Energy and Environmental Affairs 2015):

1. Coal Plant Retirements- 2.7% reduction from 1990 levels
2. Renewable Portfolio Standards- 1.1% reduction from 1990 levels
3. Clean Energy Imports- 4.2% reduction from 1990 levels
4. Clean Energy Standards

5. Regional Greenhouse Gas Initiative
6. Electric Grid Modernization

All together, by 2020 these measures will reduce greenhouse gas emissions by 8.2% from 1990's sector-wide levels, or about 7.749 MMTCO2e. This represents a ~30% reduction in emissions from the electric generating sector. Additional measures, like promoting an offshore wind industry, must be taken to achieve the goals of the Global Warming Solutions Act (80% reduction by 2050).

Offshore Wind Policy Environment

Offshore wind development in New England, and renewable energy investments more generally, are supported through a series of policies designed to support the nascent industry. The first layer of policy exists at the federal level, and is a tax credit for every MWh of energy produced by an operating wind farm. At the state level, Renewable Portfolio Standards (RPS) require load-serving entities to procure a percentage of their energy from renewable energy sources. The Act to Promote Energy Diversity, like the Solar Carve-Out before it, requires utilities to contract for 1600 MW of offshore wind capacity. Finally, the Regional Greenhouse Gas Initiative sets a cap on carbon emissions for the power sector and sets a price for carbon by allowing qualifying generators to trade their emissions allowance, indirectly helping renewable energy compete on price. The following sections discuss the details of these incentives and their impact on offshore wind development.

Renewable Portfolio Standards

Renewable portfolio standards (RPS) require retail electricity suppliers that sell electricity to end use customers to procure a certain percentage of their electricity from renewable energy generating sources (*Massachusetts Electric Utility*

Restructuring Act of 1997 1997). Massachusetts established an RPS in 1997, and later amended it through the Green Communities Act of 2008 to require retail electricity suppliers to procure electricity from three different programs:

- Class I: New (after December 31, 1997) or additional capacity from a solar PV, thermal, wind, ocean thermal, tidal or wave, fuel cells using renewable fuels, landfill gas, new hydro with a capacity less than 30 MW, low emission biomass, marine or kinetic energy, or geothermal.
- Class II: Any of the above qualifying technologies that began commercial operation before December 31, 1997
- Alternative Energy Portfolio Standard (APS): Non-renewable energy sources like combined heat and power, flywheel storage, coal gasification, and efficient steam technologies.

The program took effect in 2003, and initially required retail electricity suppliers to procure an additional 1% of electricity from Class I sources, with the standard escalating by .5% each year until 2009. Retail electricity suppliers include the three investor owned utilities (e.g., Eversource, National Grid, Unitil) and all competitive electricity suppliers (e.g., NextEra Energy Services, Harvard Dedicated Energy Limited). The 2008 Green Communities Act increased the escalation to 1% annually. Currently, the RPS requirement for Class I renewables is 12%, escalating to 15% by 2020, and 20% by 2025; for Class II renewables, the RPS was 2% in 2015 (*Renewable Energy Portfolio Standard- Class I*, n.d.). In addition to Class I and Class II requirements, there is also a carve-out for solar power from the Class I requirement, introduced by the Department of Energy Resources in 2010, that requires retail electricity suppliers to procure 1.6313% of their energy from solar in 2017

("Massachusetts Renewable & Alternative Energy Portfolio Standards: Annual Compliance Report for 2014" 2016, 1–2). Offshore wind will qualify as a Class I renewable energy source (*Act to Promote Offshore Wind Energy* 2016).

Retail electricity suppliers fulfill their requirement under the RPS by purchasing renewable energy credits (RECs) or making alternative compliance payments (ACP). Renewable energy generation units mint RECs every time they generate one MWh of electricity. This production is tracked in the Northeast Power Pool's (NEPOOL) Generation Information System. Each REC is given a unique identification number and is deposited in the generator's account. Suppliers can then either purchase these RECs directly from the generator or through a broker. Once purchased, they are transferred to the Supplier's account where they can either be banked to meet future obligations or retired to meet current year obligations. Class I RECs can be banked for two years, but the banked value cannot exceed more than 30% of a Suppliers RPS obligation ("Massachusetts Renewable & Alternative Energy Portfolio Standards: Annual Compliance Report for 2014" 2016, 8).

The RPS legislation also provides a mechanism for Suppliers to fulfill their obligation if they are unable to procure enough RECs: the Alternative Compliance Payment (ACP). The ACP is a per MWh dollar rate set by DOER that Suppliers can pay to meet their obligation, allowing them to avoid fees while also serving as a price ceiling for the REC markets. For 2017, the ACP rate was $67.70. The rate is adjusted up or down based on the consumer price index for the Northeast United States (MassDOER 2010). For the latest year that compliance information is available, 2014, suppliers needed to purchase 3.85 million RECs or ACPs. Of this amount, more than 99.8% was satisfied with RECs, with the remainder satisfied

with ACPs. At the same time, more RECs were minted in 2014 (3.979 million) than were needed to satisfy the requirement, which signifies an oversupply condition ("Massachusetts Renewable & Alternative Energy Portfolio Standards: Annual Compliance Report for 2014" 2016). REC prices in 2014 reflected this oversupply condition later in the year, as prices dropped from around $65 to around $55 from June to December 2014. Prices did not decline further due to strong demand from Suppliers for 2014 vintage RECs that could be banked for retirement in future years (Prince, n.d.).

Offshore wind will qualify for Class I RECs. This will provide a major contribution to their revenues with RECs currently trading around $45 per MWh. With wholesale electricity rates averaging around $28.94 per MWh in 2016, the Class I REC rate is a larger source of revenue than electricity sales ("ISO Newswire - Updates - New England's Wholesale Electricity Prices in 2016 Lowest since 2003" 2017).

Production Tax Credit

In addition to the renewable portfolio standards, offshore wind farms commencing construction by December 31, 2019 qualify for the federal renewable energy production tax credit (PTC). This tax credit provides a per-kilowatt-hour (kWh) tax credit "for electricity generated by qualified energy resources and sold by the taxpayer to an unrelated person during the taxable year" ("Renewable Electricity Production Tax Credit (PTC) | Department of Energy" 2017). The initial rate when the PTC was introduced in 1993 was 15$/MWh; because the rate is inflation adjusted, the value of the PTC in 2016 for wind was $23/MWh. A resource meeting the above requirements is eligible to receive the PTC for 10 years after the facility is placed into service ("Renewable Electricity Production Tax Credit (PTC) |

Department of Energy" 2017). The value of the PTC is a significant source of revenue for offshore wind facilities, with its value roughly comparable to the average wholesale price of electricity.

In December 2015, the PTC was extended so that facilities achieving construction by the end of 2019 would qualify for the credit, but the value of the PTC will be gradually stepped down so that projects commencing construction in 2017 receive 80% of the PTC's value, 2018 projects receive 60% of the PTC's value, and 2019 projects receive 40% of the PTC's value (*Consolidated Appropriations Act* 2015).

Regional Greenhouse Gas Initiative

A third major policy that makes offshore wind more competitive in New England is the Regional Greenhouse Gas Initiative (RGGI). This program is a carbon cap and trade program for the power sector in the states of Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island and Vermont. The program set an initial cap on carbon emissions in 2014 of 91 million short tons, with a 2.5% annual decrease in the cap limit from 2015 to 2020. The latest auction for carbon allowances saw clearing prices of $3.55 per short ton of carbon ("CO2 Allowances Sold for $3.55 in 34th RGGI Auction" 2016). The price of RGGI allowances is lower than anticipated because of the reduction in the carbon intensity of the generating fleet due to a shift towards more efficient combined cycle natural gas power plants. This shift is driven by historically low natural gas prices.

While the REC program directly subsidizes renewable energy generating units, the RGGI program works to internalize the social costs of carbon emissions for fossil fuel generators, increasing their marginal costs and increasing their offer prices into the wholesale electricity market. Notably, in ISO New England, the effect of the

program is to accelerate the switching from fuel sources with high heat rates[1] like coal and oil towards lower heat rate fuel sources like natural gas (Kim and Kim 2016). This same effect helps renewable energy generators gain market share.

Act to Promote Energy Diversity

The enabling legislation for offshore wind in Massachusetts is the Act to Promote Energy Diversity. This Act requires distribution companies (companies that deliver power to customers) to solicit proposals for 400 MW of offshore wind generation by June 30, 2017 and sign 15 to 20 year contracts for offshore wind power if the contracts meet a reasonability test administered by the Massachusetts Department of Public Utilities. The target capacity for these contracts is 1600 MW by 2027, with commercial operations of the first facility not to occur before 2018.

Any contract must satisfy the following criteria:

1. Enhance electric reliability
2. Reduce winter electricity price spikes
3. Be cost effective for ratepayers given the economic and environmental benefits of a project
4. Avoid line loss and mitigate transmission costs
5. Demonstrate project viability
6. Enable the inclusion of energy storage into project
7. Mitigate environmental impacts
8. Foster employment and economic development

[1] Heat Rate is a measure of how much thermal energy it takes to generate a KWh of energy that is measured in BTU/KWh.

Electricity generated at an offshore wind farm will be tracked using the NEPOOL-GIS system, and will count towards a distribution company's RPS Class I standard (*An Act to Promote Energy Diversity* 2016). Additionally, the distribution companies can recover 2.75% of the costs of a contract and project transmission costs can be recovered from federal transmission rates (*An Act to Promote Energy Diversity* 2016). The Act requires that Suppliers sign a contract with generators, bypassing the wholesale electricity markets. This feature of the bill is useful for offshore wind developers, who benefit from the long-term energy sales contract.

Passage of the Act led to an immediate interconnection application from Norwegian energy giant DONG energy for their Baystate Wind project, which would install 1000 MW offshore wind in the outer continental shelf south of Cape Cod ("A 'Transformational' Mandate: Greens Hail Massachusetts Offshore Wind, Renewables Bill" 2017).

Chapter 3: Literature Review

Basics Of Offshore Wind

Wind power harnesses the wind to push blades that spin a turbine, generating electricity. This resource is renewable, but it is intermittent and variable, with minute-to-minute changes in its production, and seasonal variation that alters its ability to produce electricity over the course of weeks or months. Offshore wind offers a few advantages over onshore wind, but is typically more expensive. First, winds are steadier offshore than onshore, leading to higher capacity factors and less intermittency. Second, offshore wind can be developed closer to load, reducing transmission costs and line loss. Third, offshore wind mitigates some of the concerns over noise, land-use, and visual impacts due to its more remote locations. Because of these factors, offshore wind in many ways is better suited for New England, a region where the population centers are primarily near the coasts, and transmission constraints make it difficult for remote land-based wind turbines to deliver power. In fact, ISO New England has identified areas near Boston and Connecticut as import constrained areas where the generation units local to the regions are not sufficient to provide power and transmission lines may not have enough capacity to deliver power. At the same time, Maine, with its 700 MW of land-based wind capacity, has been identified as export constrained, which means that the transmission lines carrying wind power to the heavy demand areas are at their maximum capacity (Hinkle, Norden, and Piwko 2010).

Technologically, an offshore wind farm is comprised of a number of individual turbines, each with four major components:

1. Tower
2. Nacelle: Contains the generator house

3. Rotor: Three blades connected to a rotor
4. Foundation

While many of the components are similar in onshore and offshore turbines, the foundation of an offshore wind turbine is much more complex than its onshore cousin, which is typically just a concrete pile. Offshore foundations can be grouped into four categories: monopiles, gravity based, tripods and jackets. Each of these structures represents a tradeoff between cost and durability, and must be chosen based on wave loads and subsurface ground conditions. Currently, monopiles are the foundation in 75% of operating wind farms, but as farms move into deeper waters, jackets and floating foundations are expected to gain more market share (Department of Energy 2017, 56)

Turbines are installed in a pattern meant to reduce wind turbulence and disruption between turbines; for offshore sites, this means that there are typically two to four rotor widths between turbines (National Renewable Energy Laboratory 2006). Inverters must also be installed to convert the electricity from direct current to alternating current and transmission lines must be laid to bring the power onshore for interconnection into the grid.

Offshore wind farms, using current technology, are located in waters less than 60 meters in depth and are within 60 kilometers of shore. While projects continue to push these limits, the majority of projects in the pipeline today fall within these bounds (Department of Energy 2017, 47). Water depth increases the total system cost, as developers must use more steel to maintain the stability of the system, or go to more costly foundation structures. Ocean depth is the primary driver of system design. The further a turbine is from shore, the greater the costs for a system

developer; these higher costs are driven by increased construction costs (e.g., transporting equipment further out to sea) and increased interconnection costs (e.g., more undersea transmission lines) (Department of Energy 2017, 48). Both of these challenges limit where farms can be constructed, although ocean depths are the primary constraint.

To achieve greater economies of scale, and reduce relative capital cost of foundations, transformers and transmission, current trends in the offshore industry are for increasingly large turbine sizes. In 2006, commercial offshore wind turbines had an average nameplate capacity of between two and four MW (National Renewable Energy Laboratory 2006, 5). By 2014, average turbine sizes increased to four MW, with additional increases to 7.1 MW by 2019 (Department of Energy 2017, 50). Moving into the 2020s, turbine manufacturers have announced plans for 10+ MW rotor designs.

In addition to increased capacities for turbines, drivetrain technologies are moving away from high-speed designs towards direct drive, medium speed, or hydraulic drive transmissions. Original equipment manufacturers are pursuing these new technologies in the hopes of improving reliability and reducing the likelihood of major drivetrain failures (Department of Energy 2017, 52).

Potential for Offshore Wind in New England

As turbine technology improves, more offshore areas will become suitable for development. As it currently stands, Massachusetts has the greatest, developable offshore wind resource of any state in the United States, with 32.48 GW of potential output in waters less than 30 meters in depth, 75.5 GW in waters 30-60 meters and 172.5 GW in depths of 60 to 700 meters. These numbers, produced in 2016 by

National Renewable Energy Laboratory (NREL), reflect 6 MW turbine power curves, an output of 3 MW/KM^2, 100 meter hub heights, exclusion for areas unlikely to be developed (wind speeds <7 m/s and depths greater than 1000 meters), and areas protected for environmental or economic reasons (e.g., shipping lanes, marine protected areas) (Musial et al. 2016, 67).

While states in the southern and western United States have larger gross resource areas than the Northeast, low wind speeds in the south and deep waters in the west make the resources difficult to develop. Massachusetts possesses a unique combination of a strong wind resource with an abundance of relatively shallow coastline. Because of this, Massachusetts possesses the largest technically recoverable wind resource (waters less than 60 meters), and the fourth largest technically recoverable wind resource in waters shallower than 30 meters (Musial et al. 2016, 34).

Notably, the capacity available offshore in Massachusetts is 19 times greater than the average electric load in Massachusetts. This is particularly important because Massachusetts imports almost 50% of its electricity, and as mentioned earlier, almost all of its fuel (Musial et al. 2016, 37). Applying a capacity factor of around 47% to the 32.48 GW of wind resources in waters shallower than 30 meters results in a total annual generation of more than 133 TWh, more than 2016's New England's Net Energy Load of 124 TWh. The intermittency of wind makes it difficult to determine the level of wind capacity to meet peak loads. In other words, the offshore wind resource, if fully developed, can generate enough electricity to meet New England's net energy load (Musial et al. 2016; "ISO New England - Energy,

Load, and Demand Reports" 2017). This does not account for the variability of the wind resource, however.

Economics of Offshore Wind

While Massachusetts has a significant offshore wind resource, there is little value in it if offshore wind is not able to deliver electricity at a competitive price. While offshore wind is currently about twice as expensive as onshore wind, DONG Energy recently signed a contract to deliver power to the Netherlands for about $77 per MWh for 15 years (this price does not include interconnection costs), a record low for offshore wind farms ("DONG Energy Wins Tender for Dutch Offshore Wind Farms" 2017). While this contract represents a new low for offshore wind costs, the U.S. Energy Information Administration (EIA) is forecasting the levelized cost of energy (LCOE) for offshore wind to be $158/MWh in 2022 without the production tax credit. This is reduced to $146.70/MWh with the production tax credit included. This compares unfavorably with traditional fossil fuel generation, which ranges from $57/MWh for Advanced Combined Cycle Natural Gas facilities to $110.80/MWh for a conventional natural gas combustion turbine. Compared with renewables, offshore wind is expected to be much more expensive than onshore wind ($56.90/MWh), solar photovoltaic ($66.30/MWh), and hydroelectric generation ($67.30) (Energy Information Administration 2016a, 7).

The range between EIA's projections of the LCOE and DONG Energy's record-breaking contract represents two dramatically different cost trajectories. If DONG Energy, which is developing the Baystate Wind Project, can successfully deliver offshore wind energy at the prices they are in the Netherlands for the Borselle 1 and 2 concession areas, offshore wind energy might fundamentally shift the generation mix in New England. Alternatively, if the EIA scenario is correct, offshore wind

energy will likely remain a promising but commercially insignificant source of energy. To get clarity on the differences between these two scenarios, its helpful to breakdown the costs of offshore wind to identify the major cost contributors, and then look at the variety of offshore wind cost projections to understand the potential trajectories.

Energy generation costs are provided in two metrics, capital costs per MW of nameplate capacity ($/MW) and expected LCOE ($/MWh). LCOE is a predicted value derived from the capital costs, the capital recovery factor (the percentage annual annuity from the project), fixed and variable operational costs, and the capacity factor. The three main drivers of LCOE are the capital costs, expected life of the project, and the capacity factor (National Renewable Energy Laboratory 2017).

$$LCOE = \{(Overnight\ Capital\ Cost\ \times\ Capital\ Recovery\ Factor + Fixed\ O\&M\ Cost) \div (8769\ \times\ Capacity\ Factor)\} + (Fuel\ cost\ \times\ heat\ rate) + Variable\ O\&M\ Cost$$

Traditional fossil fuel power plants have relatively low capital costs (around $1,100/KW) and high capacity factors (~85%) but high variable costs (driven by fuel expenditures). Alternatively, renewable facilities like offshore wind have high capital costs ($1,800-$6,000/KW), extremely low variable costs, and low capacity factors (30%-45%) (Energy Information Administration 2016b, 7). To improve the LCOE of a renewable power plant, developers need to improve capacity factors or drive down capital costs.

For offshore wind, the primary capital cost components are the turbine (49%), foundations (21%), transformer and interconnection (16%). Design, development, and internal wiring between turbines represent the remainder of the costs (Chong and Li 2016, 15). In this estimate, turbine costs include the cost of construction, not

just the turbine price from the OEM. Operations and maintenance costs for offshore wind farms represent the only significant operating expenditures, and can add between $20 and $50 per MWh of production to the LCOE (Chong and Li 2016, 16). In dollar terms, capital costs for a representative 3.4 MW turbine are shown in Table 1.

Table 1: Offshore Wind Cost Components

	3.39-MW Offshore Turbine ($/kW)	3.39-MW Offshore Turbine ($/MWh)
TURBINE CAPITAL COST	1,952	43
Development Cost	129	3
Engineering Management	97	2
Substructure and Foundation	535	12
Site Access, Staging, and Port	23	1
Electrical Infrastructure	763	17
Assembly and Installation	687	15
Plant Commissioning	43	1
BALANCE OF SYSTEM	2,277	50
Insurance	53	1
Decommissioning (Surety Bond)	159	3
Construction Financing Cost	341	7
Contingency	531	12
FINANCIAL COSTS	1,084	23
MARKET PRICE ADJUSTMENT	612	13
TOTAL CAPITAL EXPENDITURES	5,925	129

Source: (Mone et al. 2015, 41)

While these numbers represent forecasts of operational costs, its helpful to examine the only operating offshore wind farm in the United States to understand how these costs are recovered by a developer, and how ratepayers are paying for the new developments. The Block Island Wind Farm, developed by Deepwater Wind, is a five-turbine facility in Rhode Island with a nameplate capacity of 30 MW that reached commercial operation in December 2016. Capital expenditures for the project are estimated to be around $300 million, or $10,000/KW, almost double the representative costs above ("Block Island Wind Farm Now Fully Financed" 2015, *Bloomberg.com* 2016). These higher costs are likely due to the small scale of the

project, and its position as the first offshore wind in the country. A power purchase agreement provides for the sale of the bundled RECs and energy from the Block Island Wind Farm to the Narragansett Electricity Company, a subsidiary of National Grid, over a twenty-year term starting at $235.75/MWh, subject to a 3.5% annual escalation. In 2016, the bundled costs are $270/MWh. In addition to revenues from the PPA, the project receives a production tax credit for every MWh generated, amounting to around $23/MWh, along with capacity payments from ISO New England which are insignificant given the capital costs and low capacity factors (~$150,000 annually). With data on power prices from the published PPA between National Grid and Deepwater Wind, revenues from SNL, an energy research service and subsidiary of Standard and Poors, and data on costs projected from the LCOE, a cash flow model can be generated ("SNL: Financial & Operational Forecast" 2017, "Power Purchase Agreement (PPA) Between National Grid and Deepwater Wind Block Island, LLC [Docket No. 4111] | Offshore Wind Hub" 2017; Mone et al. 2015). Ratepayers pay the PPA rate for the electricity, plus any delivery charges. With average retail rates of electricity in New England around $15/MWh, the PPA rate of $24/MWh represents a significant premium over average energy prices.

Cost Projections for Offshore Wind

With the Block Island Wind Farm representing a significant premium over normal electricity rates, the future of the industry depends on a downward cost trajectory for offshore wind projects. The expectation for declines in the cost of offshore wind is based on the idea of a learning curve: as the industry gains more experience in manufacturing and construction, the price will decrease. Learning curves are driven by technological progress, input price reductions, internal efficiency improvements, learning by doing, and economies of scale (Ibenholt 2002). In the late 1990s, wind

turbines saw steady decreases in costs per KW of production as installed capacity increased (Ibenholt 2002).

Since then, however, wind, and offshore wind in particular, has not seen a steady reduction in the cost per MW. Several studies observed cost increases from 2005 through 2010 (Bolinger and Wiser 2012; Schwanitz and Wierling 2016; Dismukes and Upton Jr. 2015; Heptonstall et al. 2012). Schwanitz and Wierling demonstrate that contrary to expectations and the experience of renewables like solar and onshore wind, observed investment costs have increased as cumulative installed capacity increases, in direct contradiction to the idea of learning curve benefits. Their analysis reviews 73 planned, under construction or commissioned offshore wind projects in Europe, and regresses their costs against years, distance to shore, capacity, size, number of turbines, depth, area of project, type of foundation, and the price of steel. They find that the strongest explanatory variables are years since 1990 (positive effect of 105 Euros/KW) and depth in meters (94.91 Euros/KW). This suggests that despite increases in experience, the price per installed KW of capacity increases by 105 Euros (~$149 in 2010 dollars) each year. They posit that as the scale increases, the increased complexity of a project arising from variable seabed conditions, the internal grid connecting each turbine, and increased failure rates of turbines might negate any positive learning curve effects (Schwanitz and Wierling 2016).

Similarly, Heptonstall et al. observe that capital costs for offshore wind fell from 2000 GBP/KW in 1990 to 1500 GBP/KW in 2000, then rising to close to 3000 GBP/KW by 2010. This dramatic increase in prices in the first decade of the 21st century is seen for all electricity generation technologies, and is driven largely by

increased labor and commodities costs. Specifically for offshore wind, increasing costs were driven by supply chain constraints for turbines and increasing depths and distances from shore for the average project. With this baseline understanding of the drivers of project cost, they develop a sensitivity model that tests the effect of potential turbine costs, foundation costs, depths and distances, load factors, O&M costs, currency risks, and steel costs on a model offshore wind project. The ranges tested for each of these variables reflects estimates from a variety of academic and industry reports. They project that the best case for offshore wind by the mid-2020s is a capital cost per MWh of production of 89 £/MWh, with a worst case of 193 GBP/MWh of production. Their best estimate is that by the mid-2020s, the LCOE of offshore wind will be around 116 £/MWh, or about $174/MWh in 2009 dollars (Heptonstall et al. 2012). This estimate is echoed by the United Kingdom Energy Research Centre, which projects a cost of 115 £/MWh by 2025, with continued reductions after (Greenacre, Heptonstall, and Gross 2010, XII).

In the United States, similar trends have been observed in the onshore wind industry, with price increases from 2003 to 2010, and steady reductions in cost through 2015. NREL's 2014 Cost of Wind Energy Review utilized cost information from operating offshore wind projects in Europe, similar to the studies above, to determine the cost of a model turbine project located 20 km from shore in 15 meters of water. They found that for a 500 MW project, the capital cost would be $2.973 billion ($5,925/KW), and the LCOE would be about $197/MWh. With sensitivities for all the relevant input parameters, the offshore wind's LCOE ranged from $129-$258/MWh. While this does not represent a projection of future costs, as it reflects current technology and commercially operating facilities, it can be used as a proxy for the price of offshore wind in Massachusetts (Mone et al. 2015, 51–55).

Economic Development Impacts

While offshore wind is likely to be costlier than traditional generation sources and alternative renewable energy generation, the Act to Promote Energy Diversity explicitly calls for the inclusion of economic development impacts in any measure of the impact to ratepayers (*An Act to Promote Energy Diversity* 2016). So while the cost of wholesale energy might go up, the employment and taxation benefits from the creation of a new industry in Massachusetts might offset the increased energy costs. To understand the potential development impacts, it is helpful to review literature on the impacts of the more mature industry in Northern Europe. Additionally, research into the development impacts of other renewable power sources in the United States offer some insight into the potential impacts of an offshore wind industry in Massachusetts.

The onshore and offshore wind industries in Europe in 2007 employed more than 154,000 people spread across turbine manufacturing (37%), component manufacturing (22%), development (16%), operations and maintenance (11%), and utilities (9%). It is estimated that of these numbers, 2,800 jobs are directly attributable to the offshore wind industry (European Wind Energy Association 2009, 8). The location of the jobs varies across Europe, but the majority of jobs are found in Germany (38,000), Denmark (23,500), and Spain (20,500). The European Wind Energy Association is forecasting the number of jobs to more than double by 2025 to 330,000 as the installed capacity of wind in Europe increases to 180 GW (European Wind Energy Association 2009, 9). By 2025, EWEA is forecasting that more than 50% of wind jobs will be in the offshore wind industry.

Cameron and Zwaan looked at the employment factors of renewable energy technologies to determine the per MW effect of increased capacity on employment.

This metric, unlike the total numbers from the EWEA report, provides more clarity on the impact of a new industry on a region, as it takes into consideration the learning curve impact on job creation. Notably, they find that the wind manufacturing industry creates 4 person-years of labor per MW, installation requires 2 person years per MW, and operations and maintenance requires 0.3 jobs per MW. As the industry grows and installed capacities increase, these numbers are expected to decline. For example, in Germany, as installed capacity of wind grew from 20 GW to 30 GW, O&M jobs per MW declined from 0.75 jobs per MW to 0.6 jobs per MW (Cameron and van der Zwaan 2015).

Projecting these employment factors onto the 1000 MW Bay State Wind Farm proposed by DONG Energy, you would expect the project to require 4000 person years of labor for manufacturing, 2000 person years for installation, and 300 long-term jobs for O&M. NREL modeled the potential employment benefits more broadly than Cameron and Zwaan, and predicted the employment impacts from offshore wind development in four regional scenarios on onsite labor impacts, turbine and supply chain impacts, and induced impacts. They found that in the mid-Atlantic region, the region most similar to New England, 12 to 30 full time jobs would be supported per MW during the construction phase with 1.2 full-time jobs during the life of the turbines (Tegen and National Renewable Energy Laboratory (U.S.) 2015). Notably, their analysis includes three scenarios that model the scale effects of different penetration rates; in the low scenario (400 MW of capacity by 2030), it is assumed that the supply chain effects are minimal, and much of the manufacturing occurs elsewhere. In the high scenario, with 1400 MW of installed capacity by 2030, investment is attracted to the region and the supply chain is rapidly expanded. The difference in these scenarios is that under the low scenario, a total of 16 full time

employment jobs per MW are required from construction & development, supply chain, and indirect. The high scenario dramatically increases supply chain jobs, and results in the creation of 25 full time employment jobs per MW. In addition to the job impacts of the offshore wind industry on the Mid-Atlantic, the construction and O&M of these wind farms would generate billions in economic output. Under the medium scenario, which has 750 MW of offshore wind capacity by 2030, $1.6 billion in output is generated during the construction phase, with another $1.1 billion supported by ongoing O&M operations (Tegen and National Renewable Energy Laboratory (U.S.) 2015).

Electrical System Impacts

In addition to the economic impacts, the Act to Promote Energy Diversity requires that the offshore wind farms improve system reliability. The positive impacts on system reliability that offshore wind might have due to their proximity to the population centers might be counterbalanced by the negative effect of their intermittent and variable generation.

In 2010, ISO New England commissioned General Electric to study the impacts of wind generation on the bulk electricity system. Wind, unlike other generating sources, is dependent on an energy source that is difficult to forecast. While the system was designed to handle some unexpected events like unplanned unit outages or severe weather, the regular amount of system variability introduced by wind is greater. The Mean Absolute Error (MAE), a measure of the sum of the absolute difference between the mean observed values and each observed value, for the former events is on the order of 1-3%, while forecasts of wind have a MAE of 15% to 20%. The MAE captures the absolute difference, so forecasts can move around the mean by 15-20% in either direction. To understand the impact of this increased

variability on the reliability of the system, the ISO New England/GE study modeled the electrical system with varying levels of wind penetration up to 12 GW of nameplate capacity, comprised of both onshore and offshore wind. They modeled these impacts using GE's proprietary GE MAPS software, a fully featured grid simulation tool that simulates dispatch and transmission of electricity. They calculated locational marginal prices, transmission loading patterns, emissions, loss of load events, and impacts to system operating reserves (Hinkle, Norden, and Piwko 2010).

Overall, they find that with additional investments into the region's transmission infrastructure, wind energy could supply up to 24% of the region's annual electricity load. Even higher penetration rates of close to 34% are possible if offshore wind comprises a significant share of wind capacity. The resource mix under this scenario would reduce reliance on natural gas, and lead to similar supply levels from natural gas, nuclear, and wind. To accommodate the variability in wind's generation, power plants that can provide grid regulation would need to expand from 85 MW to 313 MW. Any plant greater than one MW that follows a dispatch signal from ISO New England can provide regulation, but those with the fastest ramp rate (ability to change power outputs) and the lowest mileage costs (marginal costs of changing power outputs) are those that serve as regulators. Additionally, total operating reserve requirements would need to expand by 2,750 MW for wind under the 20% penetration scenario. Without these increases in reserve and regulation capacity, the system would become more unreliable. At the same time, if offshore wind sites are the prime source of wind in New England, we could see a reduction in the locational marginal price of $9/MWh. This represents the price depressive effect of zero marginal cost generation, and the reduced likelihood of Ten Minute Operating

Reserve (TMOR) pricing in load constrained areas like Eastern Massachusetts (Hinkle, Norden, and Piwko 2010). TMOR is a unit that can provide additional power within ten-minutes of receiving a signal from ISO New England. ISO New England must keep enough TMOR in the market to cover the potential outage from the largest first contingency loss. For Eastern Massachusetts, as demand grows on hot days, and transmission into the region is constrained, to satisfy TMOR requirements, very expensive TMOR units must be placed in reserve that are local to the load zone, leading to high market prices.

Notably, the system can support higher levels of wind penetration if investments are made into the transmission system, with the capacity markets providing a way to incentivize more development for regulation and reserves. The study also finds that offshore wind resources reduce transmission congestion for load-constrained areas, potentially improving reliability in those areas (Hinkle, Norden, and Piwko 2010).

Greenhouse Gas Emissions Literature

The final metric that any offshore wind contract must demonstrate is that it will reduce the carbon intensity of Massachusetts' power generation. There are many methods available for wind developers to prove this, but the simplest is to determine the average emissions per MWh of the generating fleet in the regional grid, and then count the emissions offset for each MWh of wind production. Looking at ISO New England's 2015 Air Emissions Report, the average emissions factor for $C0_2$ emissions was 742 lbs/MWh of CO_2. The Report also provides the average emissions rate for the locational marginal unit (LMU), which is the unit that set the locational marginal price, or is the last unit turned on to meet the last MW of demand. For 2015, the average emissions rate of the LMU was 1,036 lbs/MWh of $C0_2$ ("Draft 2015 ISO-NE Generator Air Emissions Report" 2010). Thinking about

how offshore wind will interact with the wholesale markets when it is procured through a bilateral contract with a Massachusetts utility, it will have the effect of reducing the demand required by a utility like Eversource, which will displace the LMU rather than displacing a cleaner base-load power source like Nuclear. So, using this method, a 1000 MW wind farm that generates 3,942,000 MWh of electricity annually will reduce carbon emissions in ISO New England by 1,462,482 tons using the average emissions factor, or 2,041,956 tons using the average LMU's emission factor. The problem with the average emissions approach, however, is that it does not take into account wind's intermittent nature and the potential downstream consequences of such a major out of market power purchase (Puga 2010).

To manage this conflict, economists have designed econometric models that empirically assess the emissions reduction potential of wind on an electricity grid. The method, developed by Cullen (2008) and adapted by Kaffine et al. (2013) and Novan (2015), uses an empirical approach to determine how emissions react to increased renewable energy production. Their models observe wind production's effect on output levels from other generators, or the effect of wind production on total emissions from the grid. Using the variability of wind as a natural experiment, they are able to measure the change in emissions due to an increase in wind production (Cullen 2008; Kaffine, McBee, and Lieskovsky 2013; Novan 2015). This approach captures true grid operations, but it may misrepresent the impact of non-marginal changes to energy infrastructure (which may be the case with a large deployment of offshore wind). Non-marginal changes might fundamentally change the structure of the grid, and can't be modeled without a full dispatch model (Hinkle, Norden, and Piwko 2010).

A dispatch model replicates the optimization problem that ISO New England runs every five minutes to provide electricity for the lowest cost possible. Generators bid their available supply into the wholesale electricity market based on their marginal costs. Low marginal cost generators like nuclear power plants, hydro and wind providers typically form the base of the supply stack. From there, higher marginal cost suppliers that are able to follow demand like combined cycle natural gas power plants and coal begin to supply power. The load that can't be met through lower cost supply is met with peaking power plants, which turn on to meet daily peak loads; these are typically gas turbines, oil turbines, pumped hydro that all have high marginal costs. Once the last MW of demand is met, the marginal cost of the last supplier dictates the market clearing price, which is the price given to all other generators who are infra-marginal.

Dispatch models replicate this process by taking model generators and matching them to forecast loads. Several different types of dispatch models exist, with their level of complexity varying depending on their purpose. Capacity expansion models are used to determine what resource set might be needed to meet overall demand curves. These models have a lower time resolution than actual grid operations, so they are better at representing large changes to supply rather than minute-by-minute resource commitments. Production-cost models simulate the dispatch of generation to meet hourly or minute-by-minute loads. Grid operators and policy makers use both model types to determine the impact of policies on long-term resource planning or the impacts on costs of changes to supply. While neither model perfectly captures actual system performance, their outputs are used to inform policy and plan future grid operations (Boyd 2016).

The level of complexity inherent in these models is a function of their time resolution, and whether they are simulating the full supply stack or grouping or binning them into groups. The ISO New England Wind Integration Study utilized a full production cost model developed by General Electric, MAPS, that uses the current generator stack, the planned generator mix based on the forward capacity auctions, and regional load for New York, New England, and Quebec (Hinkle, Norden, and Piwko 2010). They also have the planned and future transmission system modeled, which allows them to test for the impact of generator location on grid reliability. With this model in place, they were able to simulate the impact of wind production on hourly grid operations, system reliability, price, and transmission infrastructure.

While this model is the most fully featured, it is both proprietary and computationally intensive. Their scenarios also input wind as a market participant, rather than an out of market energy generator, which they will be if they are contracted to produce power by Massachusetts' competitive electricity suppliers. A dispatch model that is publically available, and allows for the treatment of wind as an out of market participant is the Oak Ridge Competitive Electricity Dispatch Model (ORCED). ORCED's design and inputs are described in more detail in the following chapter.

Chapter 4: Methods and Model Design

To calculate the avoided emissions attributable to offshore wind farms in New England, I deploy the dispatch model ORCED to replicate the optimization problem used by ISO New England to match supply and demand that minimizes generation costs while meeting all reliability constraints. The model, described in more detail below, has two primary input modules that were last updated in 2011. For this analysis, I update the modules with new information on supply (generation, emission prices and fuel prices) and demand (net energy load and wind production).

Data Sources

Supply

Information on generating units for ISO New England was obtained from the 2017 National Energy Modeling System (NEMS) database ("Annual Energy Outlook 2017: Availability of the National Energy Modeling System (NEMS) Archive" 2017). ORCED's developer, Stanton Hadley, designed ORCED to utilize NEMS' supply data, so the input data required minimal reformatting to prepare it for model ingestion (Hadley 2016). Additionally, Goggins used NEMS data to simulate the impact of Do-Not-Exceed wind dispatch limits on ISO New England, and found that NEMS was the most up to date and comprehensive publically available supply data source (Goggins 2014, 20). NEMS is a model developed by the U.S. Energy Information Administration (EIA) to simulate the interaction between the economy and energy to generate forecasts for the Annual Energy Outlook. To simulate this interaction, it inputs data on supply (oil and gas, natural gas transmission and distribution, coal market, and renewable fuels), demand (residential, commercial, industrial and transportation), and macro-economic activity to determine a market equilibrium that balances supply and demand for the major U.S. census divisions ("The National

Energy Modeling System: An Overview 2009" 2009). For this analysis, information on 2016 generation for the entire United States is provided in the file pltf860.v1.201.txt. This file provides information on each operating generating unit, and includes the following variables (Table 2) used in ORCED dispatch routine:

Table 2: NEMS Variables

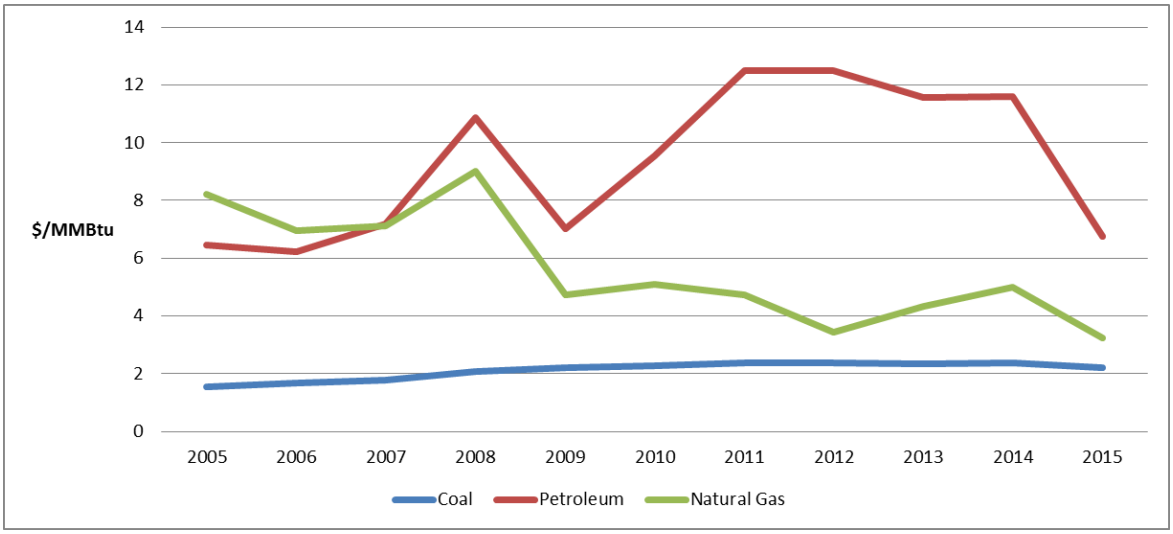
Field Name	Description
PLANT_NAME	Plant Name
EFD_type	Prime Mover
MUST_RUN	Must Run Status
NERC_OWNER (5 for ISO New England)	NERC Region
STATE	State
NAME_PLATE	Nameplate Capacity (MW)
SUMMER_CAP	Summer Capacity (MW)
WINTER_CAP	Winter Capacity (MW)
HEATRATE	Heat Rate
START_YR	Start Year
RETIRE_YR	Retire Year
CAP_FACTOR	Capacity Factor
FL1	Fuel Type
VAR_OM	Variable O&M ($/MWh)
FIX_OM	Fixed O&M ($/KW)
CAP_ADD	Capital Additions ($/KW)
NOXrate	NOX Emissions Rate
First_Op	First Operating Year
Last_Op	Last Operating Year

Source: (Hadley 2008)

The dataset itself contains over 21,000 generating units, with 962 generating units for ISO New England.

To calculate fuel costs for each generator, assumptions must be made on the cost of fuel for New England generators. With historically volatile fuel prices (Figure 6), it is difficult to accurately forecast prices.

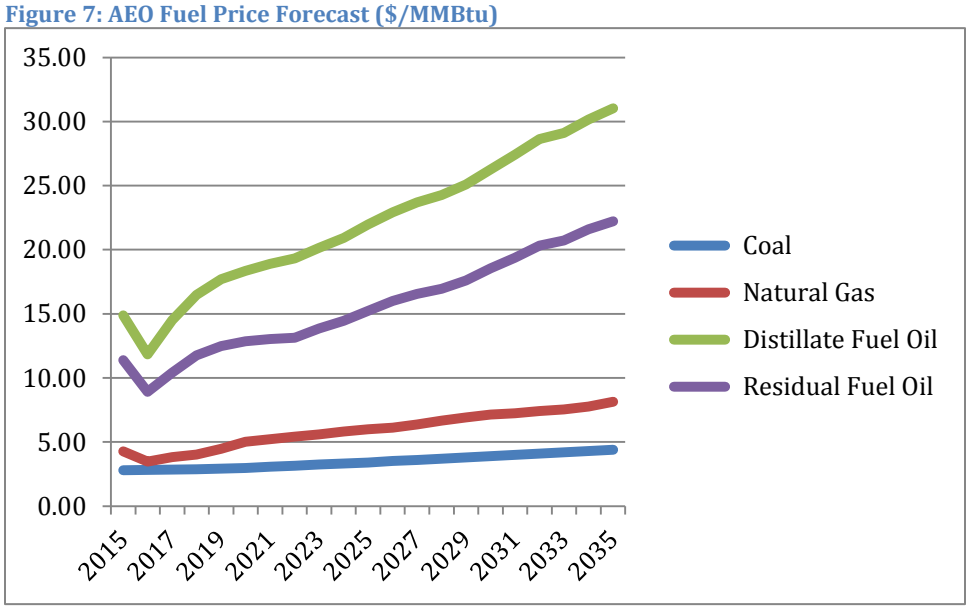
Figure 6: Fossil Fuel Prices (2005-2015)



Source: (Energy Information Administration 2017c)

EIA provides historic spot prices for fuels like natural gas, oil, and coal (Energy Information Administration 2017c). Natural gas has fallen in price from an average over $8/MMBtu to $3.23/MMBtu in 2015. This has dropped further in 2016 to less than $3/MMBtu. Coal is relatively stable, with prices ranging between $1.54/MMBtu in 2005 to $2.39/MMBtu in 2011. Petroleum has ranged from $6.23/MMBtu in 2006 to $12.48/MMBtu in 2011 and 2012. Despite this volatility, EIA's Annual Energy Outlook (AEO) provides forecasts of fuel prices through 2040. Their forecasts are derived from assumptions of macro-economic growth, technological change, and fuel supplies, thus they may provide more clarity into future fuel prices than simply using 2016 fuel prices as an input into the model. From the AEO, the following fuel prices are input into the model (Figure 7):

Figure 7: AEO Fuel Price Forecast ($/MMBtu)



Source: (Energy Information Administration 2017a)

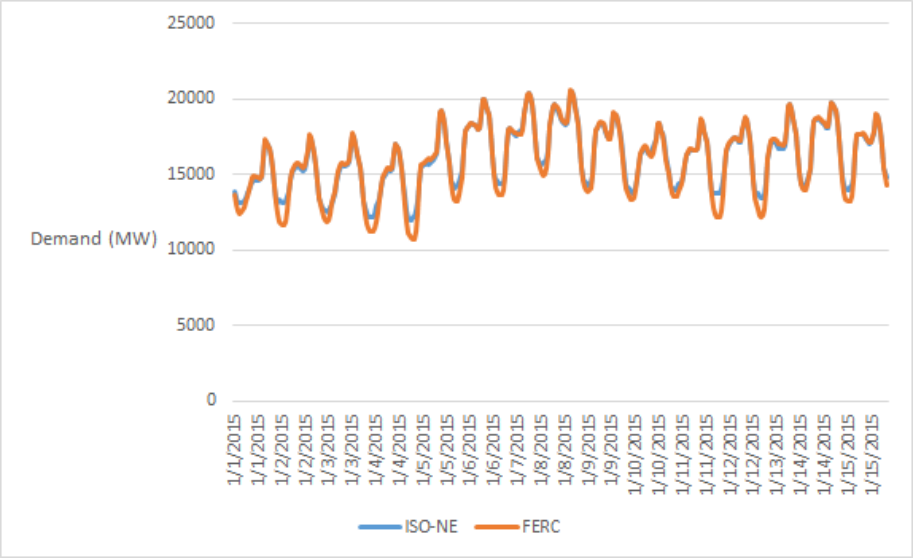
Emissions prices for SO_2 and NO_X have collapsed since 2011, when the model was last updated. At the same time, the RGGI program has created a market for $C0_2$ emissions allowances, setting a price for $C0_2$ in the Northeast and Mid-Atlantic. To capture this change, emissions prices are set to their current trading prices: SO2 allowances under the Acid Rain Program are currently trading for $0.56/short ton, NOx allowances are trading for $4.00/short ton and RGGI $C0_2$ allowances are trading for $3.14/ton ("SNL: Environmental Summary" 2017). These values are input into the model and are held constant for the base case scenario.

Demand

ORCED requires hourly load data and annual projections of net energy load to develop demand curves used in the dispatch routine. Hourly demand data for New England is available both through ISO New England and through the Federal Energy Regulatory Commission's Form 714 database. Previous versions of ORCED utilized the Form 714 database for demand, so to remain consistent with the model's design, this study utilizes hourly demand from FERC rather than ISO New England. A

comparison of hourly demand as reported by ISO New England and FERC for the first two weeks of 2015 (1/1-1/15) reveals an average difference of .93%. The difference is a result of differing definitions of load from ISO New England and how they calculate real-time demand at the system hub compared to what is reported to FERC. The load data reported to FERC is compiled annually. Regardless, as demonstrated in Figure 8, the load shapes follow each other closely.

Figure 8: ISO New England vs. FERC Form 714 Demand



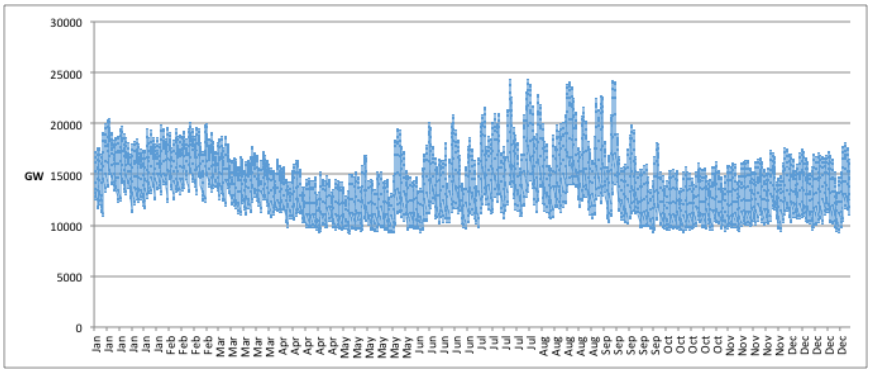
Source: ("FERC:Form 714 - Annual Electric Balancing Authority Area and Planning Area Report" 2017, "ISO New England - Energy, Load, and Demand Reports" 2017)

The latest year of demand data available in FERC's Form 714 database is 2015. Using recent data is crucial because of growth in passive demand response and distributed generation, both of which reduce net energy loads.

Hourly system load in 2015 for ISO New England is what you'd expect of a summer peaking system; peak loads during the summer, another peak in the winter, and lower demands in the shoulder seasons (Figure 9). The summer peak in 2015 was

25.761 GW, the winter peak was 20.583 GW, the average system demand for the year was 14.489 GW, and the minimum demand was around 9.046 GW in spring.

Figure 9: 2015 Hourly System Load



Source: ("FERC:Form 714 - Annual Electric Balancing Authority Area and Planning Area Report" 2017)

Wind Production

The National Renewable Energy Laboratory's (NREL) Eastern Wind Integration National Dataset (WIND) Toolkit is an update of the Eastern Wind Dataset and is used to simulate the production from an offshore wind project. The WIND Toolkit improves on the Eastern Wind dataset by expanding the date range available from 2004-2006 to 2007-2013, by increasing the number of simulated points from 1,326 to 126,000, and by increasing the grid resolution from 5km to 2km. The WIND Toolkit combines modeled meteorological data (wind speeds, wind direction, temperature, air density) with power curves for representative wind turbines to predict power outputs in five-minute intervals for the 2007 to 2013 date range at each of the 126,000 points. NREL validated the results by comparing modeled wind speeds against observed data from three offshore buoys and six onshore sites. Generally, they found that outputs for offshore sites overestimated the occurrence of wind speeds greater than 20 meters/second, but was accurate at wind speeds

below that speed. For New York Harbor, wind speeds above 20 m/s occur less than 2% of the time (Draxl et al. 2015).

Due to the variability of weather, modeled wind speeds vary year over year. In selecting a representative year, I selected the station closest to the Baystate Wind Offshore Wind Leasing Area, downloaded each dataset, and compared five-minute interval wind speeds to identify the most representative sample year. Average wind speeds, power outputs for a 16 MW project, capacity factors, and wind speed standard deviations are provided in Table 3.

Table 3: Wind TOOLKIT Outputs

		2007	2008	2009	2010	2011	2012	All Years
	Mean	7.84	7.24	7.70	8.03	7.14	6.81	7.46
Output (MW)	St. Dev	5.97	5.96	6.10	6.01	5.99	5.74	5.96
	Mean	9.44	9.10	9.34	9.70	9.01	8.71	9.22
	Minimum	0.08	0.06	0.04	0.05	0.07	0.02	0.05
	Maximum	31.65	28.29	26.84	30.09	30.17	37.98	30.84
Speed (Meter	St. Dev.	4.48	4.59	4.67	4.60	4.57	4.30	4.53

Source: Data provided by (Draxl et al. 2015)

Average wind speeds across all years are 9.22 m/s, average power production is 7.46 MW, and average capacity factors are 47%. The standard deviation of wind speed for all years was 4.53 m/s. Average wind speeds and the standard deviation of wind speeds are the primary influences on a project's capacity factor, because with stronger average winds, the resource pushes the turbine's output closer to its nameplate capacity, and with less variable wind, the generator becomes less intermittent. The year with the most representative average wind speed and standard deviation lowest was 2011, which has the third closest wind speed to the mean, and the closest standard deviation to the mean.

In addition to choosing a representative sample year, I selected a sample site from the WIND Toolkit that was closest to the Bay State Wind Leasing Area. No WIND

Toolkit sites overlap with Massachusetts' offshore wind leasing areas. Figure 10 provides the location of Massachusetts' offshore wind leasing areas, the selected wind site, and the locations of all other WIND Toolkit sites.

Figure 10: Wind TOOLKIT Site

Source: Map adapted from data in (Draxl et al. 2015)

The capacity factors of sites near the Bay State Wind leasing area range from 44.7% to 47.9% for all years while the selected site's capacity factor for all years is 46.6%, well within this narrow range. With the leasing areas further offshore than the modeled sites, you could expect capacity factors to be at the high end of the range, but for the purposes of this study, which is attempting to measure avoided emissions of offshore rather than determine a project's financial viability, we assume that the selected site is representative.

To prepare the data for input into ORCED, the output needs to be converted from five-minute intervals to hourly intervals. Additionally, instead of utilizing the wind speed or power output, I calculate the capacity factor from the power output for each five-minute interval, and then average the five-minute capacity factors across each hour. Power output is calculated by NREL and takes into account air density, wind speed, temperature and wind direction. For each scenario, the demand served by generation is reduced by the installed nameplate capacity multiplied by the capacity factor for that hour. This approach is a reasonable approximation of how a bilateral contract between a Massachusetts utility and an offshore wind project would impact the grid; instead of increasing supply in the wholesale markets, offshore wind will reduce demand because it is likely that the utility will agree to purchase all electricity produced by the offshore wind project through a contracted purchase agreement, rather than through wholesale markets.

This reduced demand, also known as the net energy load, assumes that offshore wind generation is not subject to any transmission constraints. While transmission from onshore wind resources is regularly constrained, offshore wind production

will be interconnected close to the import constrained regions of New England, Eastern Massachusetts and Connecticut (Hinkle, Norden, and Piwko 2010).

Oak Ridge Competitive Electricity Dispatch Model

The Oak Ridge Competitive Electricity Dispatch (ORCED) model was developed by the Oak Ridge National Laboratory to simulate the dispatch of generation in a competitive electricity marketplace in one region for a single year up to 2030. It uses planned generator retirements to adjust supply over time, and demand forecasts from EIA to forecast demand. It assumes no transmission constraints and predefines net exports in its calculation of average prices, marginal prices, air emissions, and generation margins (Hadley 2016).

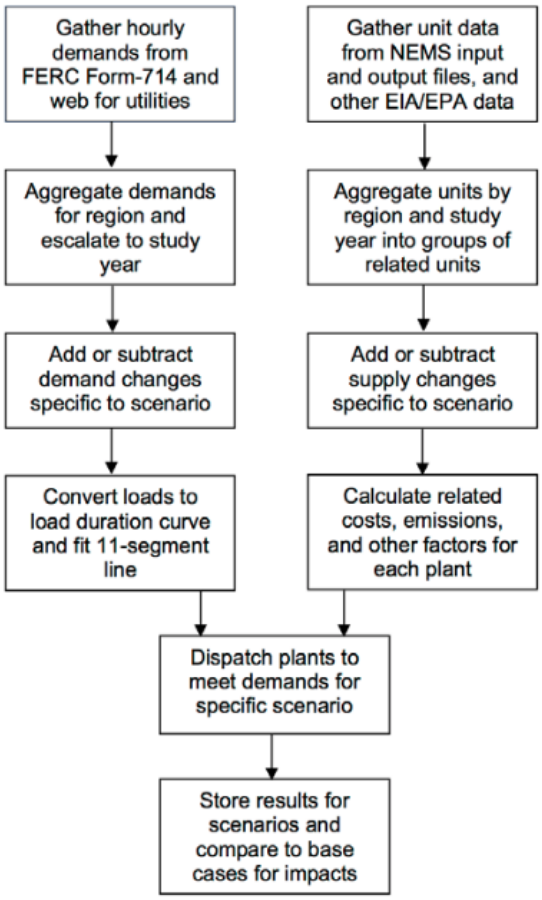
Researchers have used the model to measure the impacts of plug-in electric hybrids, carbon taxes, energy efficiency, and distributed generation on regional electricity markets. Additionally, a graduate student from UMass Amherst utilized the model to measure the effect of Do-Not-Exceed dispatch limits on wind curtailment in ISO-New England, the first application of the model to ISO-New England (Goggins 2014). This analysis utilizes many of the same methods as Goggins to measure avoided emissions from an offshore wind farm. This section briefly discusses the model's design; for a more in-depth discussion of the how the model calculates the lowest cost supply mix to meet demand, refer to Goggins and the model's technical documentation (Hadley 2016; Goggins 2014).

Model Application and Design

ORCED is a simplified model of a competitive electricity system where suppliers offer to sell electricity, and demand offers to purchase it. A regional transmission operator operates the market, and ensures that demand is met with the lowest cost

mix of supply. ISO New England serves this role in New England, and runs an optimization problem every five minutes to constantly ensure that the lowest cost supply is meeting real-time demands. A fully featured model like GE MAPS solves this problem using every generating unit for every hour of the year, but to reduce computation requirements, ORCED simplifies this process by binning the 945 generators into 200 plant groups and converting the 8760 hourly demands into three seasonal demand curves, each with 11 segments. The model follows the logic in Figure 11 to identify the generation set required to meet demand:

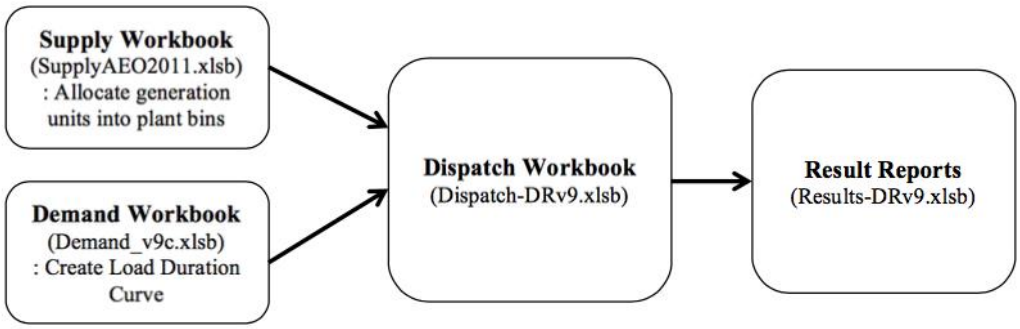
Figure 11: ORCED Model Design



Source: (Hadley 2008)

This logic is broken into four workbooks, described in Figure 12: ORCED Modules.

Figure 12: ORCED Modules



Source: (Hadley 2008)

Supply

The supply workbook takes the power plants from the 2016 NEMS database and calculates a variable cost of production ($/MWh) using fuel type, heat rates and emissions rates/prices (Hadley 2008).

$$VCi = Fi + OMi + Si + Ni + Ci$$

Where:

VCi = Variable cost for generator *i* ($/MWh)
Fi = Fuel expense for generator *i* ($/MWh)
OMi = Operations and maintenance expense for generator i ($/MWh)
Si = SO2 allowance cost for generator i ($/MWh)
Ni = NOx allowance cost for generator i ($/MWh)
Ci = $C0_2$ allowance cost for generator i ($/MWh)

This variable cost is then used in the binning routine, which combines plants based on fuel type, plant type, and variable cost (Goggins 2014, 39).

$$B_r = round\{\sum_{x \in S_r} C(x) \div Z_r\}$$

Where:

B_r = number of plant groups created for unique combination r of plant type i and fuel type j

$\sum C(x)$ = total capacity of power plants x (MW)

S_r = set of power plants x for unique combination r of plant type i and fuel type j

Z_r = user determined average plant group size for unique combination r of plant type i and fuel type j (MW)

Fixed and variable costs are then calculated by ORCED for each plant group using the weighted average of the component generation capacities.

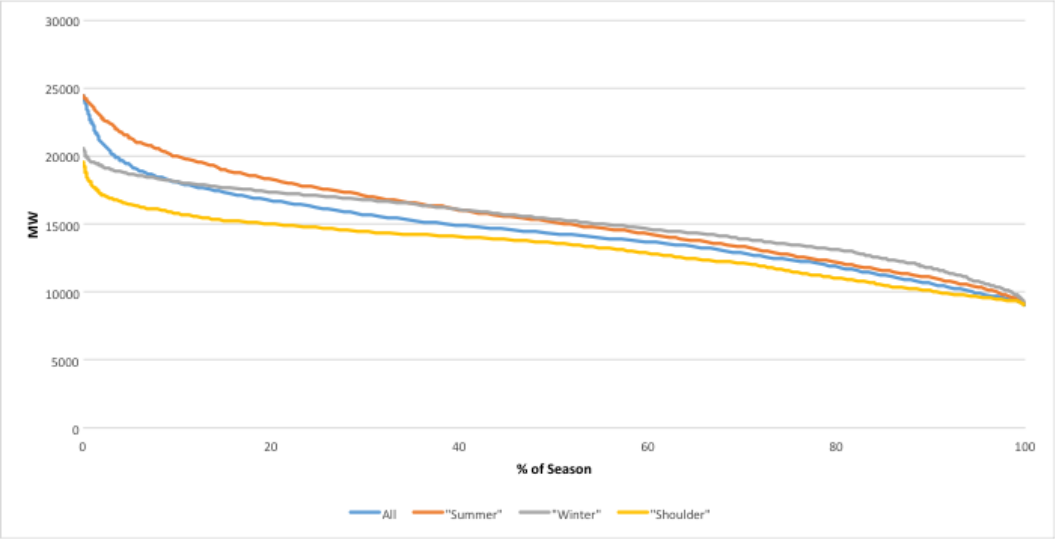
Demand

To update the demand module, new data is directly input into the "Units" worksheet. ORCED utilizes net energy load to create Load Duration Curves (LDC). ORCED defines net energy load as the input load less demand response and exports. The demand data and forecasts provided by ISO New England are also net energy load, although they are the gross load less passive demand response (e.g., energy efficiency) and solar distributed generation ("Forecast Report of Capacity, Energy, Loads, and Transmission (The CELT Report)" 2017).

ORCED then generates three LDCs, one for summer (June-September), winter (December-February), and the shoulder seasons (remaining five months), by creating 200 equal interval bins between the maximum and minimum demands and then counting the number of hours in each bin, with each subsequent bin also counting the hours in the bin preceding it. The last bin includes the sum of the all of the season's hours. Dividing each bin by the total hours (2,928 for summer) generates the LDC. For the summer LDC, the first bin with a demand between

24,360 MW and 24,437 MW has three hours representing .07% of the total hours in the season. The next bin adds four hours to the first bin; this can be interpreted to mean that .17% of the total hours in the summer have demands greater than 24,283 MW. This continues until all hours in the season are included in the LDC. The LDC for 2015 is in Figure 13.

Figure 13: 2015 ISO New England LDC



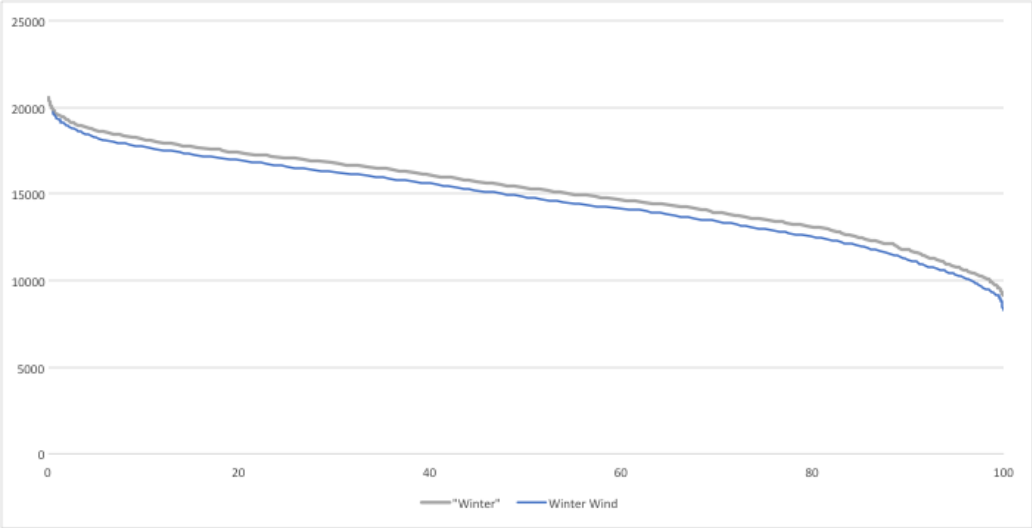
Source: Data adapted from ("FERC:Form 714 - Annual Electric Balancing Authority Area and Planning Area Report" 2017)

The LDC's shape provides information on the system's characteristics. ISO New England is a summer peaking system- apparent in the summer LDC having the highest peak demand on the left-hand axis. The slope of the curve represents the seasonal variability; a system with little variability would have a relatively flat slope. Winter has a flatter slope than summer, signifying that winter varies less than summer; this could be a result of the more stable heating load rather than the peaking air conditioning load of summer. The curve's shape also provides information on what type of generation will be used to meet demand. A flat curve

can utilize more base-load power, while a steep curve requires more load-following (intermediate) or peaking power plants (Hadley 2008).

Demand modifiers like passive demand response or wind-production will shift the curve up or down depending on how the demand modifiers are added. Subtracting demand will shift the curve down by the amount subtracted, while a percentage reduction will flatten the curve because the peak will be reduced more than the minimum. The LDC in Figure 14 demonstrates the impact of a 1000 MW wind project on the LDC. The peak demand is slightly reduced, but the minimum demand is reduced more, resulting in a marginally steeper LDC. The shift down in the LDC means that less supply will be needed to meet demand, but the increased slope will require more peaking power plants.

Figure 14: Winter LDC vs. Winter with Wind LDC



Source: Data adapted from ("FERC:Form 714 - Annual Electric Balancing Authority Area and Planning Area Report" 2017)

Dispatch

With the plant groups and the LDC's created, results are copied into the Dispatch module where the dispatch solution follows the below logic to determine marginal units, energy prices, amount of generation, and revenues for each season.

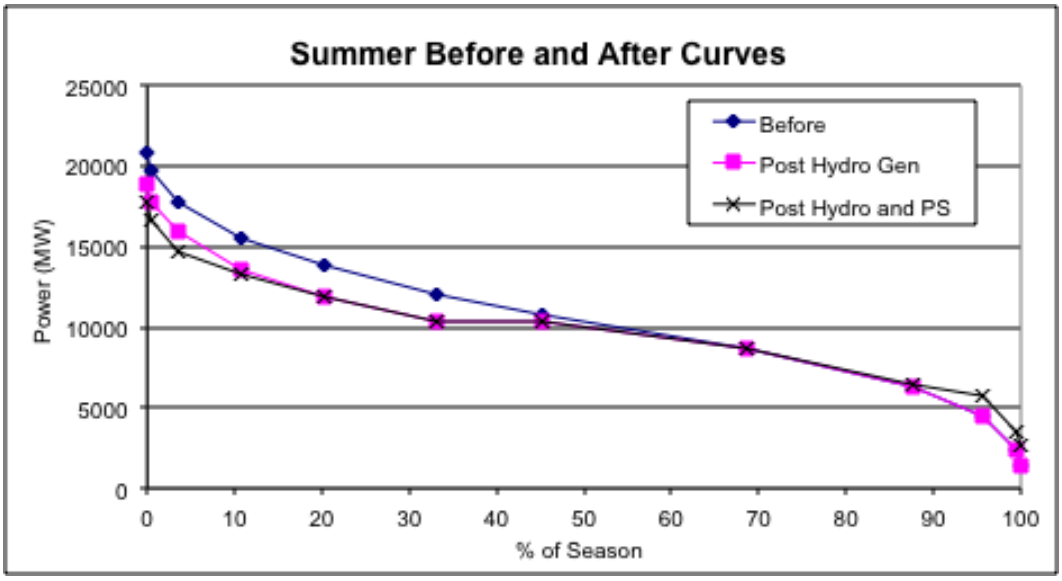
1. Adjust LDC's based on hydro and pumped storage production
2. Dispatch plants for 231 points along each season's LDC
3. Calculated unserved energy and loss of load probability (LOLP)
4. Calculate total generation by plant group
5. Calculate energy prices and revenues
6. Combine seasonal results to generate an annual result
7. Calculate emissions and other financial parameters

Adjust LDC's for Hydro Generation

The first step of the model is to take the base LDC curves for each system and then adjust them to reflect the hydro and pumped hydro generation for the region. In ISO-New England, there are 1,857 MWs of traditional hydro capacity, with another 1,177 of pumped storage hydro capacity. Because hydro power is energy limited rather than capacity limited, that is, there is only so much water upstream that can push the turbines, the dispatch optimization replaces the highest cost generation at the LDC's peak, extending down the LDC until the hydro's capacity factor limits its production further. The effect of this is to reduce the need for peaking power plants and to flatten the LDC curve (Figure 15). For pumped hydro, the plant's production is treated the same as traditional hydro with generation occurring at the high point of the curve, but the model assumes that pumping demand occurs at the bottom of the LDC, the period with the cheapest energy prices. Pumped hydro, unlike traditional which uses gravity to fill its reservoirs, uses pumps to send water uphill when electricity is cheap, and allowing gravity to push it back downhill through the turbines when electricity prices are high, effectively arbitraging the electricity markets. Pumped hydro is extremely responsive in ISO New England, and is an

important balancing resource. In ORCED, the amount of pumped generation is matched by an increase in pumped demand, shifting the right side of the LDC up. This flattens the LDC further (Figure 15).

Figure 15: Hydro LDC



Source: (Hadley 2008)

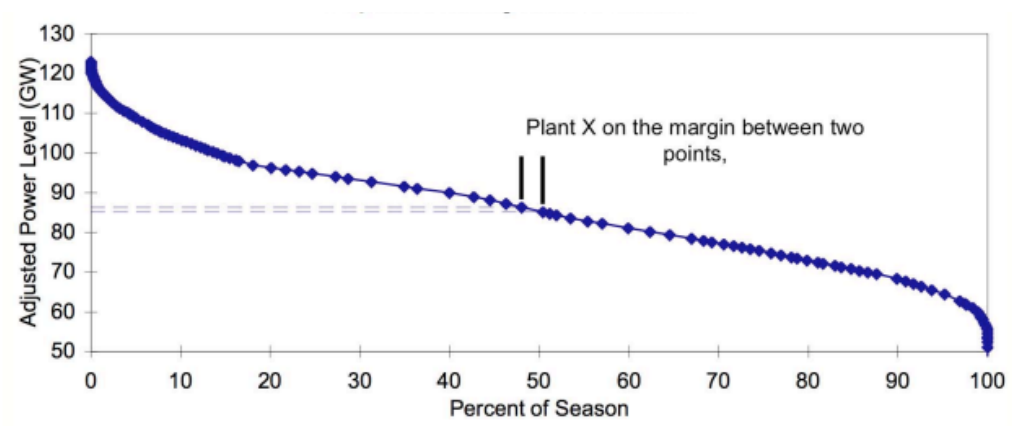
Plant Dispatch

After adjusting the LDC for hydro generation, ORCED calculates planned and forced outages for plants. This calculation can be done by de-rating power plants by their forced outage rate or through a probabilistic treatment that is a more accurate reflection of system operations. The probabilistic calculation grows exponentially for each additional plant group that is treated probabilistically, so this study treats 12 plant groups probabilistically, per the recommendation of the model's guidance (Hadley 2008). The 12 plant groups selected for unplanned outages are typically at the bottom of the supply stack. The effect of probabilistic forced outages is that the highest cost generation will operate for a few more hours compared to the de-rating

method. Planned outages occur in the shoulder seasons, replicating typical system operations.

After adjusting plant group offerings to reflect planned and unplanned outages, the model calculates power levels for ~231 points along each season's LDC and ordering plants to meet the capacity requirements and reserve requirements (7%). The last plant, also known as the marginal unit, to be dispatched to meet demand sets the marginal price. In a competitive electricity system, this plant on the margin's variable cost sets the price for itself and all other plant groups in the supply stack. The plants that are dispatched but aren't on the margin are known as infra-marginal generators; these plants earn more than their variable costs of production, generating a return for the plant's owners. Figure 16 shows the dispatch operation for 2015, with the space between two points representing the amount of time that a plant is on the margin.

Figure 16: ORCED Dispatch Showing Plant Production



Source: (Hadley 2008)

If unplanned and planned outages reduce system capacity during a peak demand period, there is the possibility that some demand will go unserved. ORCED calculates the percentage of time that there is unserved energy; this percentage

represents the Loss of Load Probability (LOLP), a key metric for system reliability monitored by system operators. In this study, LOLP is not included in the analysis because the net energy load reductions caused by offshore wind, coupled with planned generation changes, result in a lower demand curve with almost no LOLP.

Additional Calculations

Energy and revenues are calculated based on the variable costs at each of the 231 power points and the amount of generation for each plant group at those power points. For a particular power point that represents 5% of the summer season's load (~144 hours), if the variable cost of the marginal unit is 3¢/kWh, and the generator supplied 100 MW of capacity, they generated 14,400 MWh of electricity with $432,000 in revenue. Totaling the 231 power points for each season and year provides the total revenues to each plant group.

Emissions rates are calculated directly in ORCED for each plant group based on their generation amounts, fuel types, and emission factors. The basic calculation for a fossil fuel generator multiplies the heat rate (Btu/kWh) by the generation amount (kWh) to get the total Btus used by the generator. Each fuel type has an emission factor per Btu, provided in Table 4 (Hadley 2008, 29).

Table 4: Fuel Carbon Emissions Factors

Fuel Type	kg C/Mbtu
Gas	14.47
Coal	25.72
Residual Oil	21.49
Distillate Oil	21.49

Source: (Hadley 2008)

Multiplying the Btus by the emission factor provides the total emissions.

Modeled Offshore Wind Scenarios

Six scenarios are modeled in this analysis:

1. **2015 Validation Scenario:** The base inputs from the model are run to generate a scenario that can be compared to actual system performance
2. **2026 Base Case:** The base inputs from the model are escalated based on NEMS forecast to 2026, the chosen analysis year.
3. **2026 Low Wind:** 100 MW of wind are input into the model, representing a scenario where only Deepwater Wind's Block Island Wind Farm (16 MW) and their Long Island Power Project (90 MW) are constructed.
4. **2026 Medium:** 1000 MW of offshore wind are simulated for the system, representing a partial buildout of Dong and Eversource's Baystate Wind Project.
5. **2026 High:** 1600 MW of offshore wind are modeled, representing the full capacity of the initial procurement for The Act to Promote Energy Diversity.
6. **2026 High Wind:** 5000 MW of offshore wind are modeled, testing the ability of the model to simulate high wind penetration rates.

2026 is chosen as the analysis year because offshore wind generated under the Act to Promote Energy Diversity must be commercially operating by 2027. Additionally, 2026 provides enough time for development and construction to occur given average offshore wind production timelines of around a decade ("Offshore Wind Project Timelines - RenewableUK" 2017).

Chapter 5: Results/Discussion

Dispatch Model Validation

The inputs used for the dispatch model are based on observations prior to 2017 and are EIA forecasts from 2017 on. The use of historical observation data allows for a comparison of resource mix, wholesale price and emissions resulting from ORCED as compared to ISO New England's observed values. If ORCED is replicating these parameters closely, then it can be assumed that ORCED is a reasonable model of ISO New England's system. The first case modeled in ORCED is for the year 2015 with the 2016-generation mix and 2015 observed hourly demand. The 2016-generation set is applicable for 2015 because few retirements are expected in 2016, and less than 800 MW of new capacity is expected to interconnect ("Public Meeting Draft: 2015 Regional System Plan" 2015). ORCED typically scales data based on forecasts from the Annual Energy Outlook, but because 2015 is the base year, no scaling is applied. Additionally, average fuel and emissions prices from 2015 are input into the model based on average values reported by ISO New England.

Resource Mix

Resource mix and overall system production delivered by the generation fleet to meet demand from both ISO-New England's year end report and ORCED's summary tables are presented in Table 5.

Table 5: Resource Mix Validation

	ISO New England		ORCED		Difference	
Type	GWh	%	GWh	%	GWh	%
Coal	3,884	4%	11,984	11%	-8,100	-7%
Gas	52,366	49%	49,606	45%	2,760	3%
Hydro	8,068	7%	7,016	6%	1,052	1%
Nuclear	31,890	30%	31,649	29%	241	1%
Oil	1,963	2%	79	0%	1,884	2%
Wind	2,169	2%	1,450	1%	719	1%
Other*	7,577	7%	7,499	7%	78	0%
Total	107,917		109,283		-1,366	

Total production in ISO New England was 107,917 GWh as opposed to 109,283 GWh in ORCED. This difference is minimal, and is largely derived from the use of an LDC by ORCED instead of calculating generation for every five minute interval like ISO New England does. Generally, the resource mixes are similar, with a heavy reliance on natural gas and nuclear in both. The dispatch of nuclear power, a baseload source with a high capacity factor in both ORCED and ISO New England, is very close. This demonstrates that the model is handling the dispatch of baseload power in a similar fashion to ISO New England. Gas production, an intermediate source, is also similar in both models, signifying that intermediate production in ORCED is a decent replication of ISO New England's dispatch process. Production rates for low marginal cost producers like hydro and wind are also close to the observed values.

The primary difference between ORCED and ISO New England is found in the dispatch of coal and oil generation. Historically, coal was a baseload source of power, but as gas prices have fallen, coal has been forced higher up the supply stack, resulting in more intermittent generation and more time on the margin. ORCED however, treats coal as a baseload source of power. This is evident in the capacity factors for coal from ISO New England (22%) and ORCED (70%) ("Draft 2015 ISO-NE Generator Air Emissions Report" 2010). Likewise, ORCED rarely utilizes peaking

oil power plants; resulting in a relatively low total production of 79 GWh. ISO New England, on the other hand, regularly dispatches oil power plants as to meet peaking demand, resulting in total production of 1,963 GWh. This difference is likely due to the way ORCED handles demand peaks in the LDC: prior to dispatching power plants, it reduces peaking demand by the amount of hydro power available at that power point. While this replicates the ideal hydro supplier offer behavior in New England, the perfect matching of hydro supply with peaking demand in ORCED results in a greater reduction in peak demand, limiting the dispatch of peak oil power plants.

To understand whether these differences are significant, it is useful to compare year over year changes in ISO New England's resource mix. From 2010 to 2016, the range of production (difference from the maximum production to the minimum production for the period) for each resource and % of generation is presented in Table 6.

Table 6: Historical Ranges of ISO New England Resource Mix

	GWh	%	ORCED % Difference
COAL	11,577	9%	-7%
GAS	18,414	8%	3%
HYDRO	1,935	1%	1%
NUCLEAR	6,474	5%	1%
OIL	1,445	1%	2%
WIND	2,029	2%	1%
Other	1,213	2%	0%

Source: ("Draft 2015 ISO-NE Generator Air Emissions Report" 2010)

Ignoring the trends over time, the resource mix from ORCED is within ISO New England's six-year range for all fuel types except for oil.

Carbon Emissions

Total fossil fuel generation in 2015 ORCED and ISO New England differ by 5.9%, with ISO New England's fossil fuel generation producing 3,456 fewer GWh than ORCED (Table 7).

Table 7: ORCED Fossil Fuel Generation

	Fossil Fuel Generation	
	GWh	% of Production
ISO New England	58,213	54%
ORCED	61,669	56%
Difference	-3,456	

Based on this, the expectation is that ORCED's total emissions will be about 5.9% higher than reported emissions for ISO New England. With 107,916 GWh of production in 2015, ISO New England reported 40,312 kTons of $C0_2$ emissions. This results in an average emissions factor of 747 lbs of $C0_2$ per MWh. With 109,283 GWh of production, ORCED calculated 33,332 kTons of $C0_2$, resulting in an average emissions factor of 610 lbs $C0_2$ per MWh.

The cause of this difference lies in how emissions are calculated in ORCED and in ISO New England's annual emissions report. In ORCED, emissions are calculated by multiplying a standard emission factor (kg C/MBtu) for each fuel type (Table 4) by the plant's average heat rate from NEMS (Btu/kWh) and the total generation (MWh) calculated by ORCED. The emissions factors are converted from kg of C to kg of $C0_2$ using the conversion factor 44/12 (~3.67). In comparison, ISO New England bases total and marginal emissions rate calculations off of air emissions reported by the EPA's Clean Air Markets Division database (CAMD), RGGI, NEPOOL GIS or EPA's eGRID 2012 database. The source of data depends on a power plant's governing

regulations, with ISO New England preferring to use CAMD, then RGGI, NEPOOL GIS, and finally eGRID.

Emissions reported by CAMD are not calculated using the heat rate data applied by ORCED, but are based on flow rates observed by the Continuous Emissions Monitors located at the power plants. Staudt compared the two methods for coal plants and found that the predicted fuel uses are within 10% of each other in 85% of plants, although a clear trend one way or the other is difficult to ascertain from their findings (Staudt 2016). The differences between the two methods could explain some of the difference. Applying the emissions calculations used in ORCED to the generation mix reported by ISO New England yields total $C0_2$ emissions of 29,462 kTons for fossil fuel generation (Table 8).

Table 8: Emissions Calculation Correction

	ORCED Heat Rate (BTUs/KWh)	ISO Generation (kWh)	Emissions Factors (KG CO2/MMbtu)	Carbon Emissions (kTons)
Coal	10495	3,884,000,000	94.31	4,242
Gas	7497	52,366,000,000	53.06	22,985
Oil	13097	1,963,000,000	78.8	2,236
Total				29,462

Source: ORCED Model Output

29,462 kTons of $C0_2$ emissions is 7.5% less than ORCED's modeled emissions rate; scaling the emissions up to match the fossil fuel generation rate in ORCED's resource mix results in total emissions of 31,211 kTons, 1.5% less than ORCED. Another factor that may contribute to the large difference is the exclusion in ORCED of emissions from renewable resources like municipal waste, biomass, and landfill gas. These resources are included in ISO New England's air emissions report, but total emissions by fuel type are not provided so it is difficult to determine the effect of this inclusion on total emissions.

Wholesale Prices

Wholesale prices in 2015 for ISO New England averaged $41/MWh. ORCED's modeled wholesale prices are $30.30/MWh, ~26% lower than the actual value. The difference between the two is partially explained by ORCED's limited generation from high variable cost peaking power plants. ORCED's peaking power plants have a negligible capacity factor (<1%) and production (79 GWh). The cost of these marginal power plants can exceed $200/MWh, so not having them set marginal prices during peak demand depresses prices.

Validation Summary

ORCED was able to replicate the pattern of ISO New England's resource mix and generate a CO_2 emissions rate that is within 7.5% of ISO New England's emissions when ISO New England's emissions rates are re-calculated to reflect the methodology applied by ORCED. This validation effort highlights the utility of the model in forecasting the future mix of the grid, as demonstrated by its ability to closely replicate the 2015 resource mix. With coal being the one resource with a large difference (+11%) from ORCED to ISO New England, we can review the model's results with the following caveat: the carbon emissions intensity of the grid's actual performance fleet might be less than forecast by ORCED because ORCED is over-utilizing coal power plants. This bias in ORCED is mitigated because by 2026, very little coal capacity is available for dispatch.

Model Results

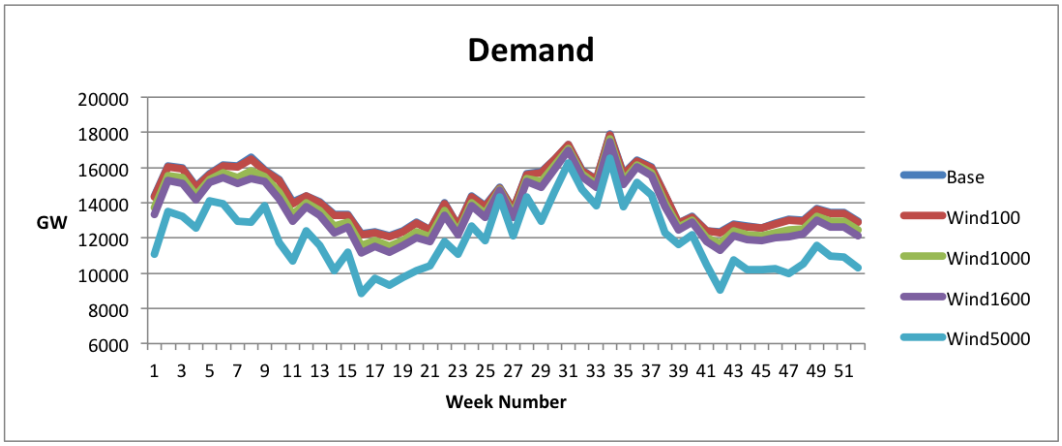
Moving from the validation scenario in 2015 to the test case scenarios for 2026, ORCED scales demand to the AEO forecast amount, retires power plants with

scheduled retirements before 2026, and adds capacity for power plants scheduled to interconnect before 2026.

Changes in Demand

For each offshore wind capacity scenario, demand is adjusted to reflect the project's production by adjusting hourly demand down. The impact of these adjustments on average weekly demand for ISO New England is demonstrated in Figure 17.

Figure 17: 2026 Modeled Weekly Demand

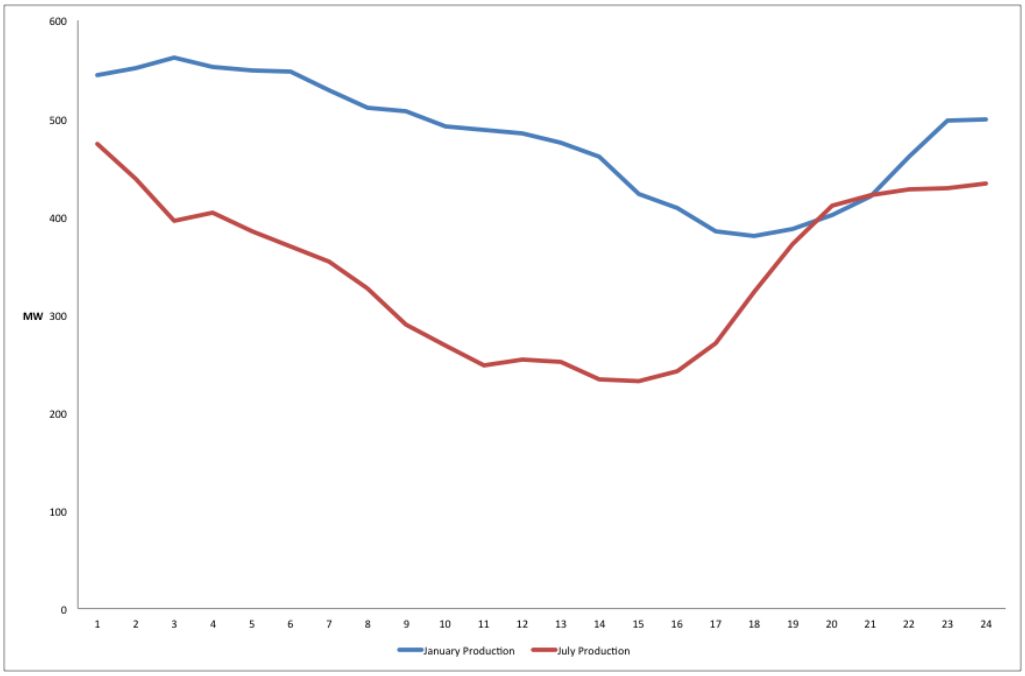


Source: ORCED Model Output

The same sample site from the WIND Toolkit is used in each scenario, resulting in total production being a simple multiple of the project's nameplate capacity. Seasonal variance in wind production is apparent in Figure 17, with larger reductions in demand at the tails of the chart, which correspond with stronger and steadier winter winds. The summer peak, occurring around week 30, sees the smallest level of wind production, and the smallest decline in demand for all scenarios. The natural seasonal variation in wind speeds does not align with ISO New England's summer peaking pattern; in other words, demand is highest in the summer when wind speeds are at their lowest while wind speeds are at their highest during winter, when demand is lower. Figure 18 demonstrates average wind

productions for a day in July compared with a day in January for the 1000 MW medium offshore wind scenario.

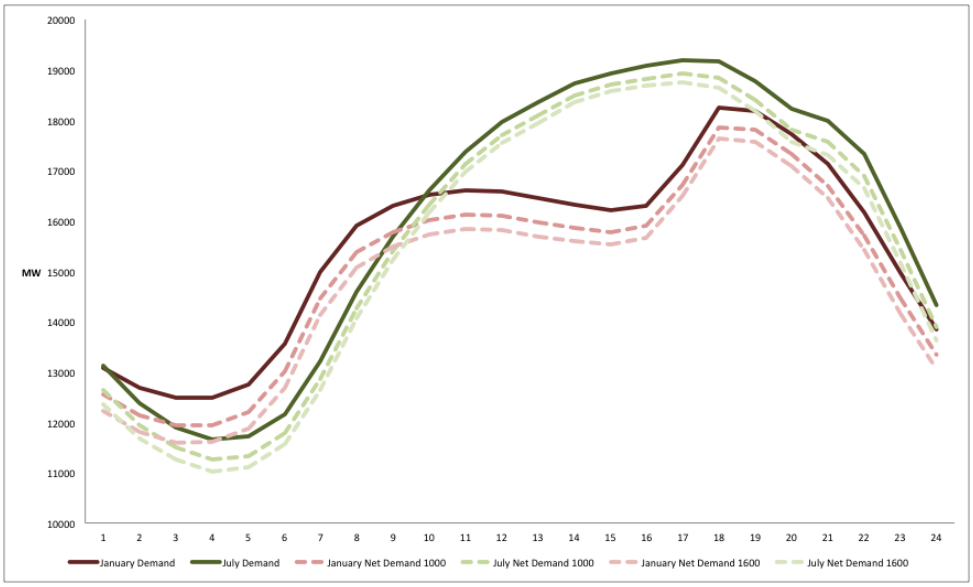
Figure 18: January and July Wind Production



Source: Data provided by (Draxl et al. 2015)

Wind production is higher on average in the winter, with a dip in the afternoon. The summer is reversed, with higher production in the evening and early morning, dropping during the day. Figure 19 plots the average July and January demands along with the demand net of wind production to visualize the impact of offshore wind production from a full buildout of Baystate Wind (1000MW) and a full procurement for The Act to Promote Energy Diversity (1600MW).

Figure 19: January and July Average Demand Curves



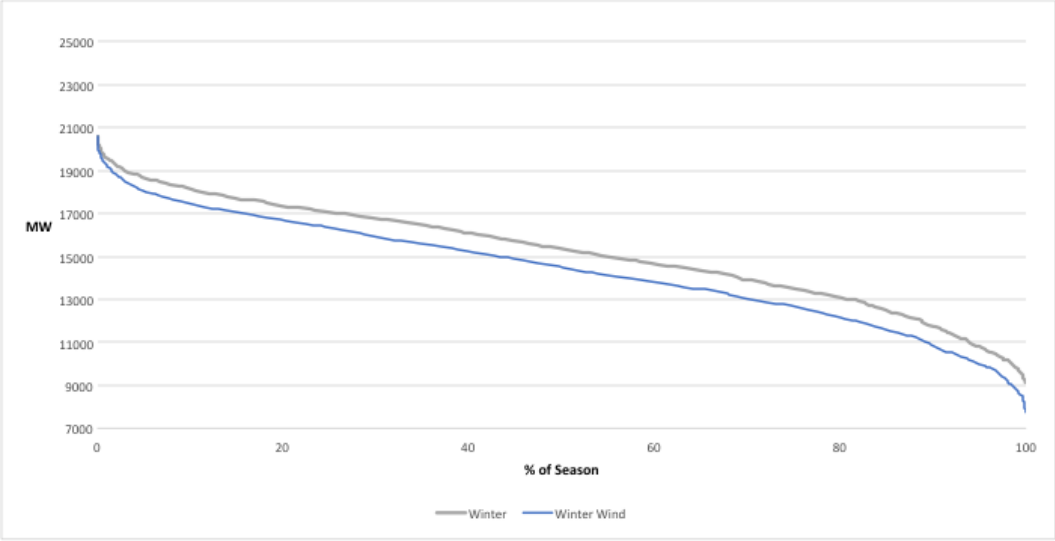
Source: Data provided by (Draxl et al. 2015)

In the summer, the morning peak in wind production, as demonstrated in Figure 19, corresponds with the average morning's minimum demand. With prices often low or negative in the morning, this production peak is poorly timed. Conversely, the summer's evening wind production peak occurs around hour 19, a few hours after the peak demand for the day (~hour 17). Winter wind production exhibits a similar shape as the summer production, but average wind production remains higher. While the morning peak again corresponds with the day's lowest demand, the evening peak production occurs at hour 19, right around January's average demand peak. Winter wind production, with its higher average production, aligns better with winter's demand curve than summer wind production.

The reduction in seasonal peak demand and seasonal demand lows is reflected in the LDC's generated by ORCED (Figure 20 and 21). Examining LDC's replicated using the same method as ORCED, the larger impact of the winter offshore wind is seen in a greater shift down in the LDC. Additionally, the peak shaving that occurs in winter

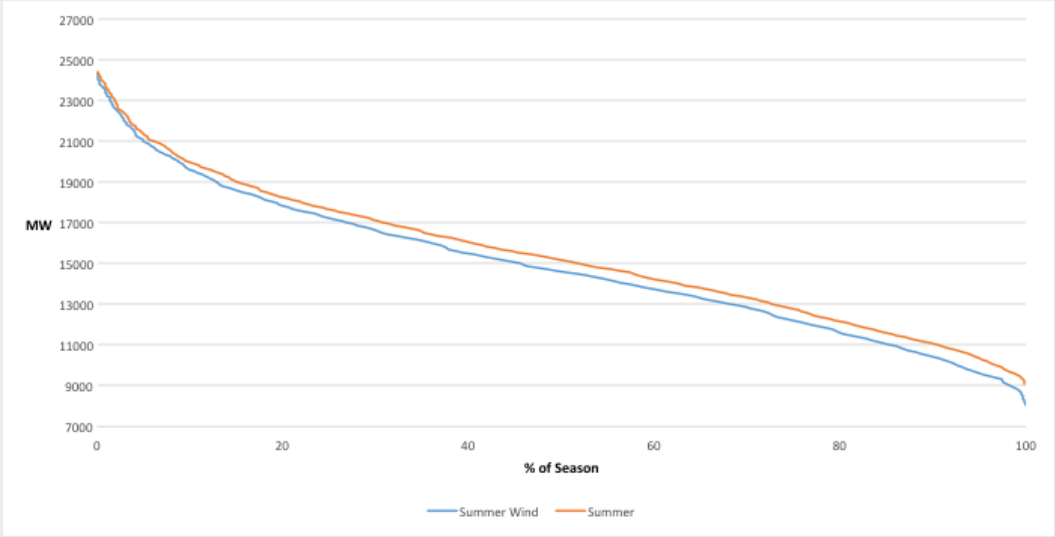
is seen in the hours closest to the peak, with significant shifts down in the LDC until the LDC curves up for the peak demand hours. Alternatively, the summer demand curve gradually shifts down, with greater production occurring during the demand minimums and much less demand shaving occurring at the peak.

Figure 20: Winter LDC and Winter LDC net of Wind Production



Source: Data provided by (Draxl et al. 2015)

Figure 21: Summer LDC and Summer LDC net of Wind Production

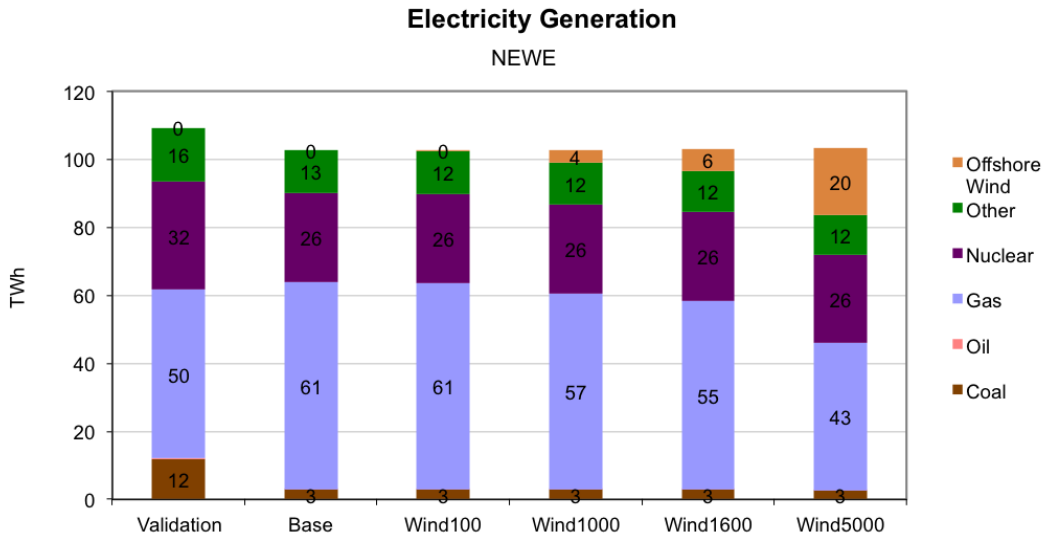


Source: Data provided by (Draxl et al. 2015)

Changes in Resource Mix

The impact of these shifting LDC's is that ORCED is forced to re-dispatch power plants to meet the new demand amount, changing the resource mix. Figure 22 provides the amount of electricity generation by resource type for all scenarios. The Validation scenario, which occurs in 2015, is included for comparative purposes.

Figure 22: Total Electricity Generation



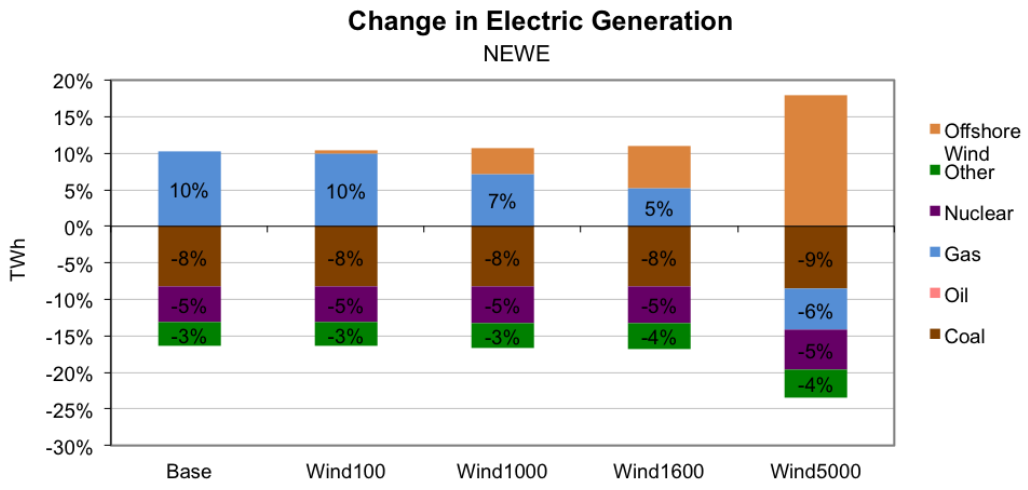
Source: ORCED Model Output

Overall generation declines from a high of 109 TWh to around 102 GWh in 2026. This reflects the EIA's forecast for increased penetration rates of distributed generation and increased imports from outside of ISO New England. These changes reduce the need for in-region bulk electricity generation. Net energy loads for the same period are forecast to decline by 2 TWh while imports are forecast to increase by ~5 TWh. Figure 22 also highlights the changing resource mix; from the 2015 Validation scenario to the 2026 Base scenario, coal production is modeled to

decrease by 9 GWh. This change reflects the closure of several coal power plants, including Brayton Point, and is not due to offshore wind production.

The changing system is better represented in Figure 23, which shows the percentage change in generation from 2015 to 2026 under each scenario.

Figure 23: Change in Electric Generation



Source: ORCED Model Output

From 2015 to the base 2026 scenario, the system adds 11 TWh of natural gas generation, loses 9 TWh of coal, 6 TWh of nuclear, and 3 TWh of other resources[2]. This reflects the forecast shift in resources as natural gas prices continue to fall and independent power producers invest in more gas resources while retiring their other resources. As offshore wind is added on to the system however, gas production is displaced; with a full procurement of offshore wind under the Act to Promote Energy Diversity, gas increases by 5 TWh instead of 11 TWh under the base scenario. It is also important to note that under every wind scenario, the

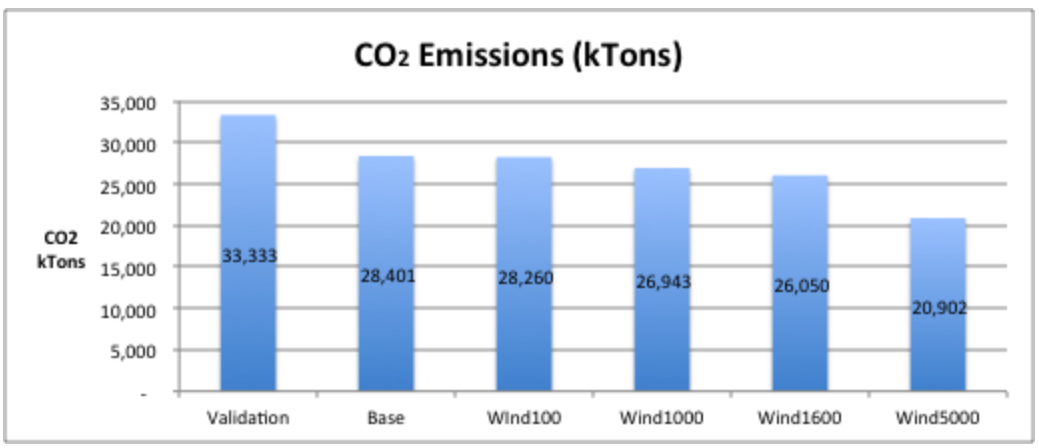
[2] Other resources in ORCED includes municipal solid-waste, biomass, onshore wind, and geothermal.

displaced resource is primarily natural gas, with only a small amount of coal and other resources displaced by offshore wind production. The effect of this shift is that instead of displacing coal, offshore wind will be primarily replacing natural gas power plants, which emit about 45% less $C0_2$ than a coal.

$C0_2$ Emission Under Each Scenario

The base 2026 scenario sees a total system reduction of close to 4,932 kTons of $C0_2$ emissions from 2015, largely due to the resource changes described in the previous section (Figure 24). With 100 MW of wind installed, an additional 141 kTons of $C0_2$ is reduced from total system emissions. The Baystate Wind Project, with 1000 MW of capacity, would reduce emissions by 1,458 kTons from the base scenario, while the 1600 MW capacity scenario would result in a reduction of 2,351 kTons.

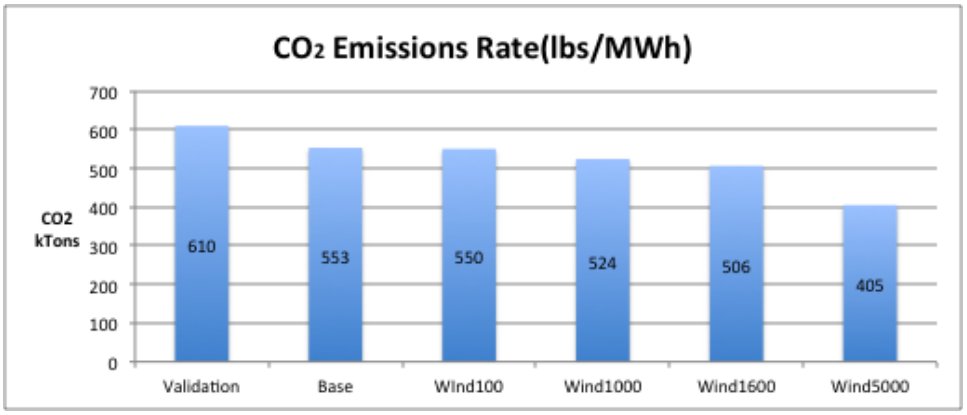
Figure 24: CO_2 Emissions



Source: ORCED Model Output

The emissions rate of the system decreases as more offshore wind is added to the system, from a Validation scenario level of 610 lbs/MWh to 405 lbs/MWh in the high offshore wind scenario (Figure 25).

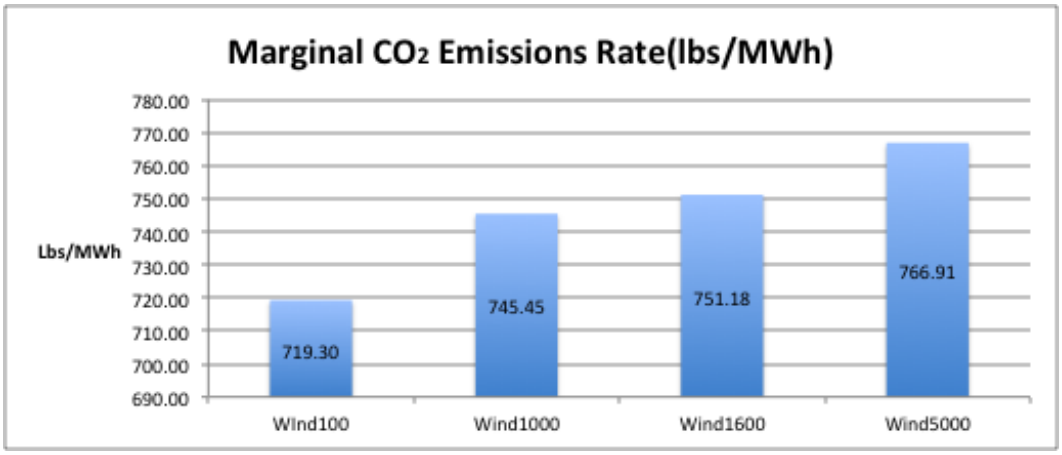
Figure 25: CO_2 Emissions Rate



Source: ORCED Model Output

It is not surprising that overall emissions rates go down as more offshore wind capacity is added, but the effect of each MWh of offshore wind production is less certain. In Figure 26, we see that as installed capacities of offshore wind increase, the marginal emissions reductions from an additional MWh of wind increase, from 719 lbs/MWh with 100 MW to 766 lbs/MWh with 5000 MW. As more wind capacity enters the system, generators with higher emissions rates are displaced.

Figure 26: Avoided Emissions per MWh of Offshore Wind Production



Source: ORCED Model Output

Emissions reductions from a MWh of offshore wind are greater than the emissions rate of the system as a whole because offshore wind is primarily displacing natural gas, coal and oil which have an average $C0_2$ emissions rate of 1,012 lbs./MWh. The system emissions rate includes generation from renewable resources like hydro and wind, and zero emission sources like nuclear.

Chapter 6: Analysis

Findings in Context

Several other studies have calculated the impact of wind on total system emissions. These include Goggins (ORCED Dispatch Model) (2014), the New England Wind Integration Study (GE Maps Dispatch Model) (2010), and Novan (econometric model)(2015). The findings from these studies, along with the actual emissions rates reported by ISO New England, are in line with the results described in the previous section. Given this, ORCED could be a useful tool for policymakers trying to understand how offshore wind might impact the bulk electricity system in New England, both because it is simpler than more fully-featured production cost models, and more responsive to policy changes than econometric or marginal emissions methods.

Comparison with New England Wind Integration Study (Hinkle, Norden, and Piwko 2010)

The GE Maps dispatch model calculated the emissions reductions for each of their modeled scenarios, which are based on penetration rates rather than installed capacities. Their medium scenario (14% penetration) modeled between 6.13 GW and 7.25 GW of capacity, while their high scenario modeled between 8.29 GW and 10.24 GW (20% penetration). They find a total emissions reduction of 12,000 kTons with 20% penetration of offshore wind (~9 GW). The highest penetration scenario modeled in this thesis was 5 GW, which resulted in a net reduction of 8,600 kTons of $C0_2$ emissions. The rate of emissions reductions is similar between the two studies, with an 800-900 lbs./MWh reduction seen for their 20% scenario as compared to the 766 lbs./MWh reduction scene in the high scenario from this study (5 GW). With the rate of reductions increasing as more capacity was added to the system, the rate would likely fall into the range of the Wind Integration study.

Comparison with Goggins (Goggins 2014)

Goggins, who modeled the ISO New England system with an older version of ORCED, found that for every 3.2 GW of wind capacity, there was a reduction in $C0_2$ emissions of 5000 kTons. This study found that with 1600 MW of installed capacity, emissions were reduced by 2,351 kTons. Doubling this rate to get to 3.2 GW gives us a reduction of 4,702 kTons. While the modeled years differ between the two studies, the reduction in system level emissions is similar.

Econometrics Results

Several studies have measured the change in emissions attributable to wind production using econometric methods. The most recent of these studies, Novan (2015), builds on the work of Cullen (2008) and Kaffine (2013) to measure the emissions avoided due to wind production in Texas' regional electricity system, the Electric Reliability Council of Texas (ERCOT). While the resource mix and system characteristics of ERCOT differ from ISO New England (48% gas, 28% coal), it is still useful to compare the results of a dispatch model approach with an empirical study. Novan found that for every MWh of wind production in ERCOT, $C0_2$ emissions were reduced by .63 tons, or 1,260 lbs./MWh. This is higher than we find in ISO New England, but this is expected due to the higher share of fossil fuel generation in ERCOT (79.5%) as compared with ISO New England (54%).

Study Limitations

The findings described in the results section are similar to the results of other studies, but like any model, they will always fail to perfectly replicate ISO New England's dispatch procedure. Emergency operations, operator error and any number of unpredictable events can impact the system and throw off the integration of offshore wind.

Most importantly, however, ORCED is not a good model for testing the reliability and intermittency issues caused by higher penetration levels of offshore wind. The New England Wind Integration Study is focused on testing how the transmission and generation systems react to different penetration levels, but ORCED is unable to replicate this analysis because it does not model transmission and because its use of LDCs reduces the variability of wind production. The lack of a transmission model is less important for this study because offshore wind in Massachusetts will interconnect into import constrained regions, limiting any transmission congestion (Hinkle, Norden, and Piwko 2010). The smoothing of wind production variability through the creation of LDCs makes it difficult to assess whether peaking production might increase as traditional generators are forced to balance offshore wind production that can vary minute to minute. The slope of the LDC's does capture some of this variability, but its low time resolution is a fundamental constraint when modeling the impact of wind production on system reliability. Production cost models that look at sub-hourly temporal resolutions are better used for assessing the finer changes caused by increasing intermittency.

The Act to Promote Energy Diversity: Revisited

As mentioned in the beginning of this thesis, the Act to Promote Energy Diversity requires any offshore wind contract to satisfy the following conditions:

1. Enhance electric reliability
2. Reduce winter electricity price spikes
3. Be cost effective for ratepayers given the economic and environmental benefits of a project
4. Avoid line loss and mitigate transmission costs

5. Demonstrate project viability
6. Enable the inclusion of energy storage into project
7. Mitigate environmental impacts
8. Foster employment and economic development

This study is unable to answer all of these questions definitively, but it does offer some insight into whether or not offshore wind is likely to pass these tests.

Enhance Electric Reliability

While the ORCED model does not provide much clarity on the reliability of the transmission and generation system in Massachusetts, coupling the results from ORCED with the findings of the New England Wind Integration Study suggests that offshore wind has the potential to reduce reliance on natural gas and relieve import constraints for Eastern Massachusetts. One of ISO New England's primary reliability concerns is the potential for winter outages ("Winter Reliability Solutions for 2015/2016 to 2017/2018 Key Project" 2017). While peak demands are lower in winter than in summer, the heavy and growing reliance on natural gas could lead to undersupply conditions during the winter. Natural gas shortages occur in winter as opposed to summer because the gas distribution system and residential customers have priority to use gas before the electric system. Generators located at the tail of the pipeline may not be able to procure enough natural gas to maintain generation, and may experience forced outages. When these outages occur during cold periods, the capacity of ISO New England to meet demand is strained.

While building more natural gas infrastructure could alleviate this reliability concern and is the preference of ISO New England, alternatives like energy efficiency could reduce the constraint (Knight and Stanton 2016). While not

explicitly addressing winter reliability, offshore wind production is likely to reduce winter peak demands, reducing the demand for natural gas. As shown in Figure 18, the winter LDC shifts down as offshore wind production increases. The winter peak demand also shifts down because, on average, daily peak wind production occurs within one hour of the daily peak demand. Additionally, results from ORCED demonstrate that the resource mix in the region changes in scenarios with at least 1000 MW of wind capacity from one that is more than 60% reliant on natural gas, to one that is no more than 55% reliant. This shift is greater in the winter, when wind production is highest. The New England Wind Integration Study also found that wind production would be greatest in the winter, although the report did not draw any conclusions about winter reliability changes.

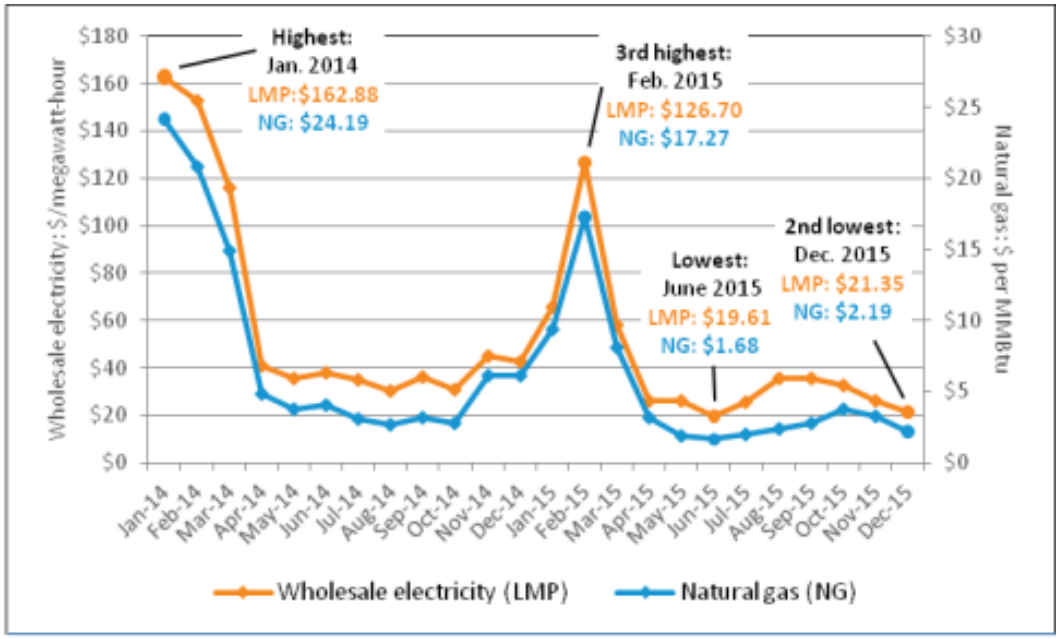
ORCED did not test to the impacts of offshore wind's variability on reliability, but the New England Wind Integration Study did model the impacts of variability on reserves and transmission. They found that offshore wind improves the effective load carrying capability of wind resources as compared to onshore wind. Their study finds that the system will maintain its current loss of load expectation (<1 day every 10 years) with up to 32% of capacity provided by wind resources, 58% of which are offshore. The study did report a minor decrease in import constraints for the Boston area as compared to the other scenarios, but did not draw any conclusions from this reduction (Hinkle, Norden, and Piwko 2010).

Reduce Winter Electricity Price Spikes

ISO New England's increasing reliance on natural gas power plants is exposing them to reliability and price risks caused by limited pipeline capacity. Reliability concerns are discussed in the previous section, but when demand for gas from pipelines

carrying gas to electric generators and distribution companies exceeds pipeline capacity, natural gas prices rise, increasing electricity rates (Figure 27).

Figure 27: ISO New England Gas and Electricity Prices



Source: ("ISO Newswire - Updates - New England's Wholesale Electricity Prices in 2016 Lowest since 2003" 2017)

The highest prices in Figure 27 occur during the winter when natural gas prices increase; these price increases are caused by high demand for gas for heating in addition to electricity generation. Offshore wind can reduce these price spikes by decreasing reliance on natural gas and by shaving peak demand in the winter. As discussed in the previous section, offshore wind has the highest capacity factor during the winter, and its average production curve aligns well with the winter demand curve. Winter demand peaks occur within one hour of wind production peaks, reducing the need for more expensive peaking power plants. Additionally, by diversifying the resource mix and decreasing reliance on natural gas, increased capacities of offshore wind reduce demand for natural gas, reducing gas prices, and decrease the need for natural gas generation, limiting electricity market exposure to

natural gas prices. Offshore wind capacity of 100 MW does not accomplish this because it only reduces natural gas reliance by 0.53%, but penetration rates greater than or equal to 1000 MW reduce reliance on natural gas by between 5% and 28%.

Cost Effective for ratepayers given the economic and environmental benefits of project

The environmental benefits of an offshore wind farm primarily come from the avoided greenhouse gas emissions resulting from increased wind production. Using EPA's 2025 social cost of carbon based on a 3% discount rate, Table 9 presents the benefit of offshore wind production under each scenario.

Table 9: Value of Avoided Emissions per MWh

	Wind100	Wind1000	Wind1600	Wind5000
Installed Capacity	100	1000	1600	5000
Offshore Wind Production (MWh)	391,147	3,911,475	6,258,359	19,557,373
Avoided Carbon Emissions (tons)	127,619	1,322,596	2,132,417	6,803,278
Value of Avoided Emissions	$ 5,870,461	$ 60,839,416	$ 98,091,179	$ 312,950,774
Value of Avoided Emissions per MV	$ 15.01	$ 15.55	$ 15.67	$ 16.00

Source: ORCED Model Output; (US EPA 2016)

Every MWh of wind production reduces carbon emissions by ~750 lbs., and results in a net savings of ~$15. Using the social cost of carbon, wind production generates a clear net benefit, with the total benefit increasing at an almost linear rate as capacity increases.

Offshore wind is also the recipient of several governmental subsidies: the Production Tax Credit and Renewable Energy Credits. With the production tax credit set to expire by 2020, the sole subsidy for offshore wind production is likely to be RECs. Vintage 2016 Class I RECs are trading for $17 and 2017 Class I RECs are trading for $26. This is a significant price reduction from average 2015 prices around $50, and average 2016 prices around $40. RECs capture the environmental value of one MWh of renewable energy production and are paid for by competitive

electricity suppliers, who end up passing the cost on to consumers. While there may be environmental benefits other than carbon emission reductions, for consumers to be paying the "fair" price for the value of a MWh of offshore wind, they should be paying around $15/MWh- the value of the avoided emissions for each MWh of wind production. With REC prices greater than $15, ratepayers are paying more for avoided emissions than they are receiving in benefits. It is important to note, however, that the EPA provides a range of SCCs that vary based on the discount rate applied (2.5%-5%) and the potential for low-probability but high impact events. Using these ranges and the 1600 MW installed capacity scenario, the possible values of one MWh of avoided emissions from offshore wind are listed in Table 10.

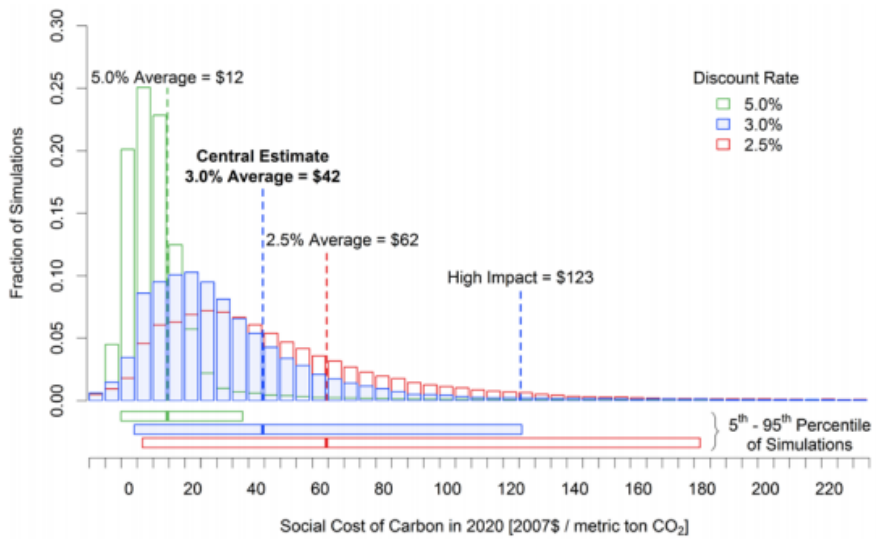
Table 10: Range of Values from Social Cost of Carbon

Social Cost of Carbon	Discount Rate	Value of Avoided Emissions per MWh
Low	5.0%	$ 4.77
Medium	3.0%	$ 15.67
High	2.5%	$ 23.17
High Impact Low Probability	3.0%	$ 47.02

Source: (US EPA 2016)

Using the SCC as the basis of the value of avoided emissions implicitly assumes the error ranges that result from a number calculated using integrated assessment models. Additionally, the point estimates from EPA are designed to be used for policy analysis, but do not reflect the true uncertainty of the SCC estimates. Figure 28 provides the full distributions for each estimate. While the mean of the simulations for a 3% discount rate in 2020 is $42/ton, the actual cost might vary from close to $0/ton at the 5th percentile to $120/ton at the 95th percentile (US EPA 2016, 5).

Figure 28: SCC Distribution from Technical Update of the SCC for Regulatory Impact Analysis



Source: (US EPA 2016)

In addition to paying for RECs, ratepayers will be purchasing power from the project through their utility's power purchase agreement. If the contract is structured like the Block Island Wind Farm, then ratepayers will pay a premium for the offshore wind. Assuming LCOE rates from the NREL study (129-258) and DONG's record-breaking PPA (77$/MWh) to set electricity prices, and bundling RECs with the purchase price at $15/MWh, the total cost to consumers under each scenario per KWh of production ranges from 9.2¢/KWh to 27.3¢/KWh. For a representative customer in Boston that is currently paying 9¢/KWh for electricity (not including transmission or other charges), DONG's premium rate is competitive with current offerings but rates based on NREL's LCOE estimates will cost ratepayers more. With the benefit from carbon emissions reduction already included through the use of bundled RECs, the question is whether the economic benefits to consumers outweighs the price premiums.

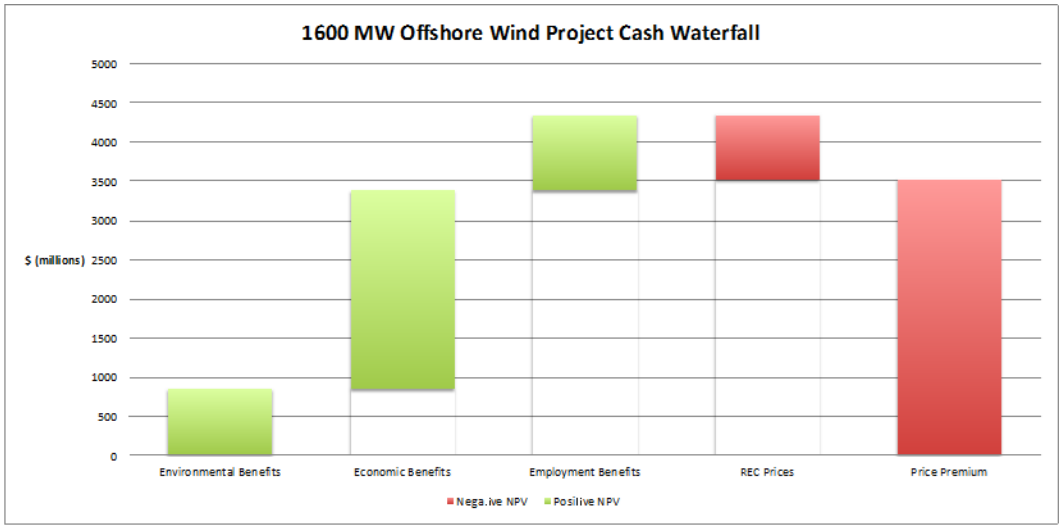
The value of energy independence, increased employment, and indirect economic benefits are discussed in the background section of this thesis. Based on an annual fuel expenditure of $18 billion dollars, with 25% coming from the power sector, the state spends $4.5 billion on fuel for electricity annually, with most leaving the state (MA Executive Office of Energy and Environmental Affairs 2015). This represents a tremendous transfer of wealth out of Massachusetts. A 1600 MW wind farm would not be able to replace all of the fossil fuel generation in Massachusetts, but it will reduce expenditures on natural gas by about 10%, or 450 million dollars. Instead of transferring $450 million dollars out of state, the money could be transferred to employers and companies based in Massachusetts. While this is not a direct benefit to consumers, it is a more positive outcome than transferring money out of the state to pay for fuel.

The economic development impacts of a wind farm, as modeled by NREL, are expected to increase as installed capacities grow, reflecting the growth of a local industry to support offshore wind development. Under a medium scenario, which sees 1900 MW of installed capacity by 2020, the industry will support more than 5000 full-time equivalent positions during construction and 2300 jobs during the operations and maintenance period. For the same scenario, $390 million in earnings and $1,310 million in economic activity will be generated during construction. This falls to $180 million in earnings and $490 million in economic activity during the life of the wind projects (Tegen and National Renewable Energy Laboratory (U.S.) 2015).

These economic development impacts are forecasts, and may be low or high depending on whether the offshore wind industry establishes itself in

Massachusetts. All together, the environmental benefits, the economic benefits, and the employment benefits are significant for the offshore wind industry. A gross cost-benefit analysis, using the aforementioned parameters as inputs and assuming that all Massachusetts residents share in the economic and earnings benefits equally, finds that the project is cost-effective for consumers at prices below $179/MWh (Figure 29).

Figure 29: Costs and Benefits of Offshore Wind



Source: Author

Foster Employment and economic development impacts

See section "Cost Effective for ratepayers given the economic and environmental benefits of project".

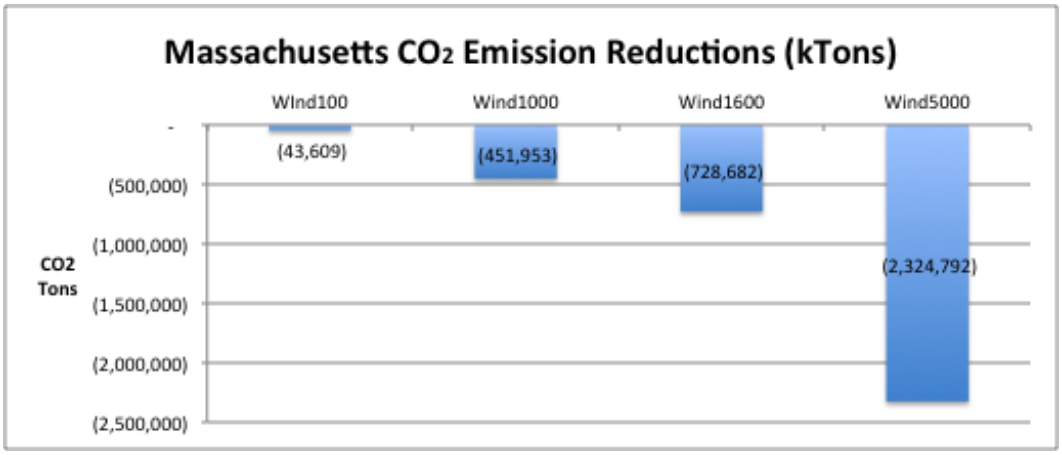
Clean Power Plan

Under the Clean Power Plan, Massachusetts needs to reduce $C0_2$ emissions from the power sector to a rate based level of 824 lbs./MWh by 2030, or a mass based total of 12,104,747 short tons. The latest full year inventory of Massachusetts GHG emissions, 2014, reports 14,800,000 short tons of $C0_2$ emissions for the electricity-

generation sector (DEP 2012). This results in a rate based emissions factor of ~874 lbs./MWh based on ISO New England's reported generation ("ISO New England - Energy, Load, and Demand Reports" 2017). For Massachusetts to reach their 2030 goals, they need a further reduction of 50 lbs./MWh, or over 2,000,000 short tons.

With Massachusetts' generators producing about 31% of ISO New England's electricity, Massachusetts would share in the emissions reductions from each offshore wind scenario (Figure 30).

Figure 30: Massachusetts CO_2 Emissions Reductions



Source: ORCED Model Output

The 5000 MW scenario reduces emissions enough to meet the Clean Power Plan's 2030 goals. Alternatively, the 1600 MW scenario does not reduce emissions enough to achieve the 2030 goal, but in concert with energy efficiency measures, distributed generation, and the retirement of coal power plants, it may play a significant role in achieving the goal.

Chapter 7: Conclusion & Recommendations

Offshore wind is a unique opportunity for Massachusetts to move towards energy independence, reduce its carbon footprint, and make a major investment in a growing industry. It is also imperative that Massachusetts takes a bold step towards carbon neutral electricity generation to mitigate the impacts of climate change. With the Clean Power Plan on hold, the onus for $C0_2$ emissions reductions will have to come from states rather than the federal government. Investing in offshore wind promises to push Massachusetts to the forefront of the clean energy economy, while sending a clear message to the world that the United States is still committed to $C0_2$ emission reductions. In addition to the avoided $C0_2$ emissions resulting from an offshore wind project, the economic and employment benefits along with energy independence from imported fuels all add value to an offshore wind farm.

While a wind farm with power prices exceeding $179/MWh may not be a good deal for consumers, DONG Energy may be able to deliver a project for prices lower than that. In that scenario, the economic and environmental benefits offset the premium ratepayers in Massachusetts will end up paying for offshore wind. As the scale of offshore wind increases, the benefits to Massachusetts's residents and businesses grow, with new industries relocating to Massachusetts to support the industry. Because of this, and the relatively high cost of smaller farms like Deepwater Wind, regulators should seek to procure the full 1600 MW called for in The Act to Promote Energy Diversity, with contingencies to cancel contracts if power prices exceed the overall benefit to Massachusetts.

Future studies should compare the cost effectiveness of offshore wind against other $C0_2$ emissions reduction methods, like energy efficiency measures and distributed renewable generation. Because learning curves have not been realized in offshore wind, other methods for achieving low carbon intensity may be a cheaper option.

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