Massachusetts Renewable Energy Potential

Final Report

Prepared for

Massachusetts Department of Energy Resources (DOER) and Massachusetts Technology Collaborative (MTC)

August 6, 2008

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Content of Report

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Assignment and Purpose

The analysis herein was performed by Navigant Consulting, Inc. (NCI) under the direction of the Department of Energy Resources (DOER) and the Massachusetts Technology Collaborative (MTC). The goal of the study was to examine renewable energy market penetrations based on **hypothetical future states of the world**, defined based on DOER and MTC assumptions. NCI compiled and assessed currently available literature, and conducted stakeholder interviews to assess the capacity installed (MW) and generation (MWh/year) of a range of RE technologies that could be developed within the state by 2012 and 2020.

Context and Limitations

The work presented in this report represents NCI's best efforts based on the best information gathered by NCI and provided by DOER and MTC at the time the report was prepared. NCI prepared this report, from June through August 2008. NCI performed limited primary research for the resource assessment.

NCI analyzed a series of scenarios based on DOER and MTC assumptions that describe different hypothetical states of the world. The scenarios do not represent an NCI prediction or forecast, and they are not meant for predicting or bounding the most likely future.

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Navigant Consulting, Inc. (NCI) worked with DOER and MTC staff to examine market penetrations in MA for renewable energy technologies.

Scope
• NCI worked with the Department of Energy Resources (DOER) and Massachusetts Technology Collaborative (MTC) staff to identify the renewable energy (RE) technologies of interest, and key reports/contacts having information about them. • NCI reviewed the literature and conducted interviews to gather information about the theoretical and technical potentials, technical and economic characteristics (costs, capacity factors, etc.), available incentives for, and barriers to the deployment of the RE technologies in Massachusetts (MA). • NCI analyzed a series of scenarios based on DOER and MTC assumptions that describe different hypothetical states of the world. The scenarios do not represent an NCI prediction or forecast, and they are not meant for predicting or bounding the most likely future. • NCI built a framework for modeling the economic potential and market penetration for the RE technologies under the different scenarios.

The goal was not to predict the future, but rather to look at penetrations under different potential future states of the world.

NCI's analysis addresses selected renewable energy (RE) *resources* and *technologies.*

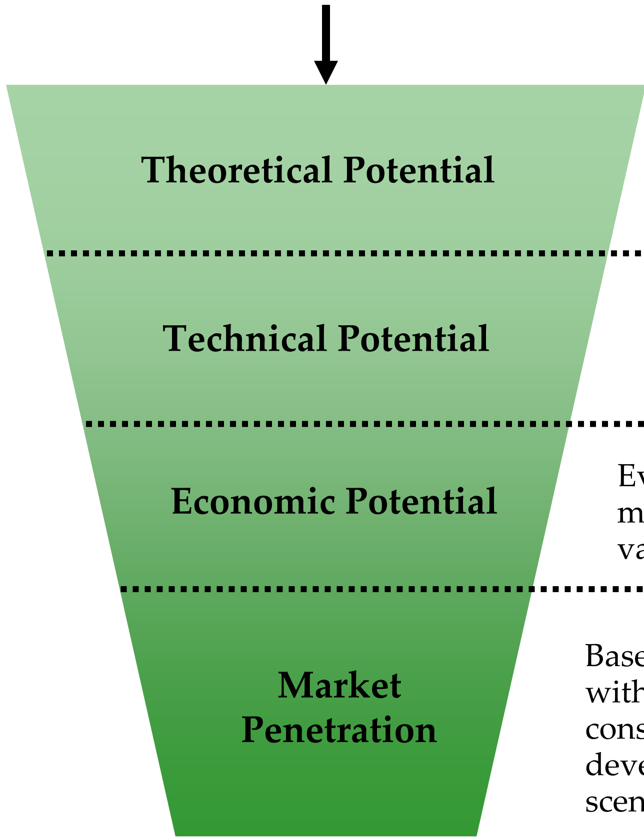
Renewable Energy Resource	Technology Type
Solar	Photovoltaics – Primarily Rooftop
Wind	Onshore
	Offshore
Biomass	Co-firing
	Direct combustion
	Gasification
River	Small hydro
Ocean	Wave
	Tidal

PV was analyzed differently. The purpose was to determine incentive levels needed to achieve the 250 MW installed capacity goal by 2017.

Note: As agreed upon with DOER and MTC, this report does not consider the geothermal resource or technologies designed to produce energy from solar thermal energy, landfill gas, anaerobic digestion, or large hydro sites.

NCI's assessment of market penetration follows a successive evaluation to go from theoretical potential to market penetration.*

Renewable Energy Technologies and Resources



Total resource potential unconstrained by land use considerations or other non-economic factors. Conducted on a technology-by-technology basis. Theoretical potentials do not vary by scenario.

Factors out resources that cannot be accessed due to non-economic reasons (e.g., land use restrictions, siting constraints and regulatory prohibitions), including those specific to each technology. Technical potentials do not vary by scenario.

Evaluates resources that cannot be developed because they are more expensive than competing options. Economic potentials vary by DOER and MTC scenario.

Based on the economic potential, estimates the timeline associated with the diffusion of the technology into the marketplace, considering the technology's relative economics, maturity and development timeline. Market penetrations vary by DOER and MTC scenario.

* For this analysis, PV was analyzed in a different manner. For each of the scenarios, NCI analyzed the incentive package needed to achieve the Commonwealth's goal of achieving 250 MW of PV installed capacity by the end of 2017.

A series of scenarios were developed based on DOER and MTC assumptions that examine economic potentials and market penetrations.

Scenarios

An approach to long-term planning in situations with significant uncertainty about important future events

- Future scenarios developed around high impact/high uncertainty "change elements" (drivers).
- Plans may be developed under alternative scenarios, then compared for similarities and differences.
- The scenarios are meant to examine a number of plausible future states of the world.
- The scenarios are not predictive.
- The scenarios can help identify key issues and explore alternatives.

Eight exogenous (outside of state control) drivers impacting RE development in MA were identified.

Drivers	Definitions
Commodity Prices	Level of inflation in commodity prices, including steel, concrete, and oil, but not natural gas.
Consumer Demand	Degree of consumer and societal demand/support for renewable energy (e.g., through green marketing programs) and environmentally friendly energy policies.
GHG Policy	Aggressiveness of the greenhouse gas (GHG) regulatory environment.
Green Spread	The differential between the cost of producing RE and the market price of grid-supplied conventional electricity. The market price of electricity reflects both the natural gas and carbon dioxide prices.
Government Incentives	Strength of the federal and state policies providing financial incentive for RE projects. The focus is on select incentives: the federal production tax credit (PTC), investment tax credit (ITC), and renewable energy credits (RECs) resulting from the Massachusetts renewable portfolio standard (RPS).
Load Growth	The size of the increase in demand for electricity, based on established rates of economic, population, and electricity consumption growth (including the impact of efficiency or smart grid developments).
Non-incentive Regulation	Level of support provided by federal and state provisions that are not incentives but do impact RE projects (e.g., permitting and siting provisions). GHG policy is excluded here and analyzed separately.
Transmission Investment	Development, or lack, of adequate transmission capacity to allow continued growth in renewable electricity generation and delivery.

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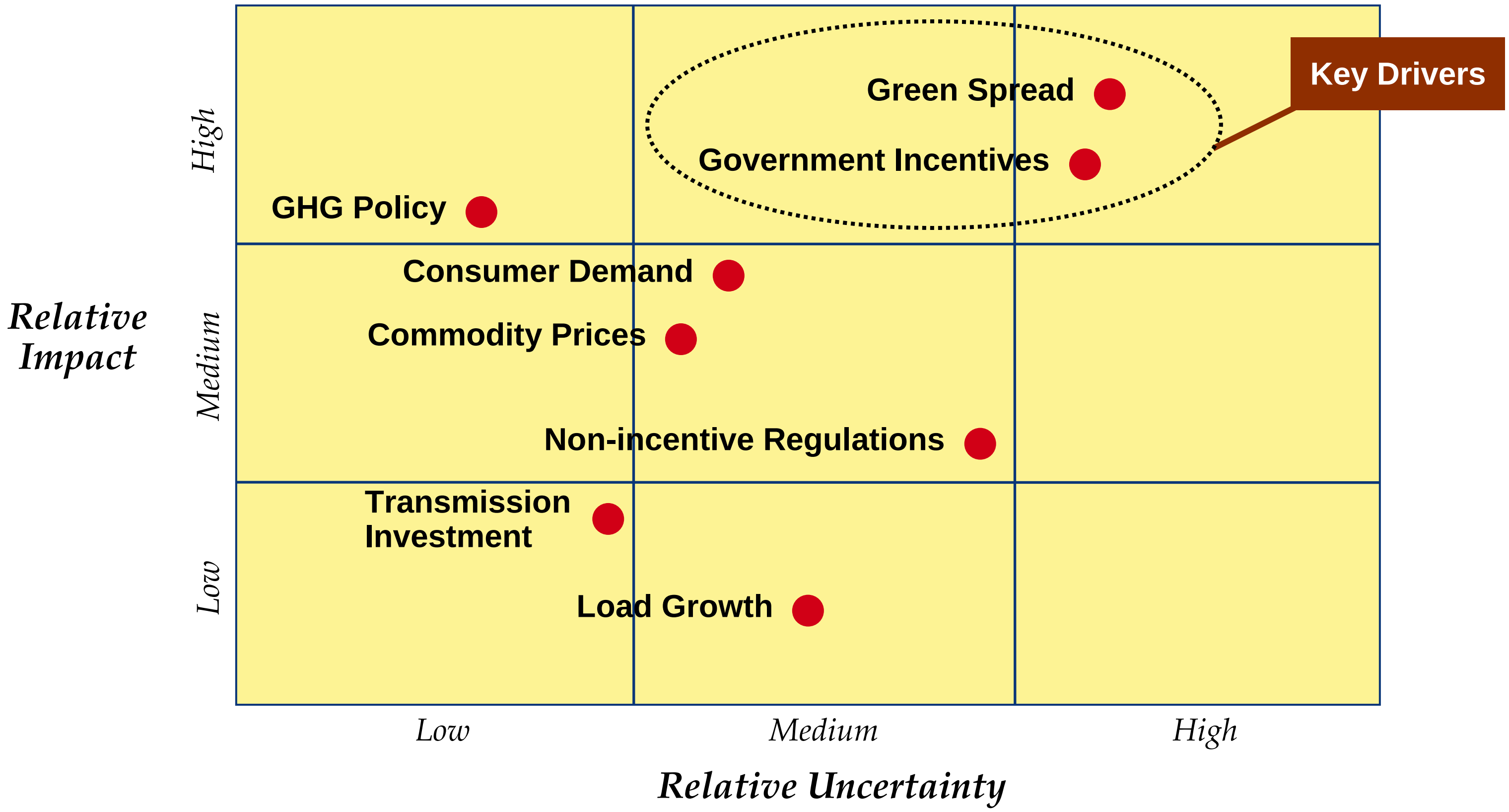
Scenarios were developed around the two drivers with the highest potential impacts and most uncertainty.



Note: The positioning of the various drivers based on NCI estimates of their relative impact and uncertainty.

Two high-level drivers are poised to shape the power industry and impact RE penetration more than any others.

Green Spread	Government Incentives
• The difference between the cost of producing renewable energy and the market price of grid-supplied conventional energy. — Natural gas pricing is frequently the fuel that determines the market price of electricity in the New England market. • The two components of this driver (RE cost and market price) maintain a consistent relationship in determining the direction of the Green Spread. — Lower RE cost, and higher grid price, lead to higher Green Spread. — This consistent relationship allows us to consider them together. — Future Green Spread values are highly uncertain, and can have very high impact on the pace of RE development.	• The regime of government incentives impacting RE development, focused for this analysis on select incentives for RE projects: — RECs resulting from the Commonwealth's RPS — Federal PTC — Federal ITC • As the price of RECs and the values of the PTC and ITC rise, the economics of RE projects improve. • State incentive programs outside of RPS-driven RECs and government policies outside of incentives (e.g., siting and permitting rules) are not included as part of this driver.*

* They are considered as part of the analysis but are held constant across the scenarios while the incentives included in the Government Incentives driver are varied across the scenarios as is explained in the subsequent slides.

These two drivers---Green Spread and Government Incentives---form the basis of the scenarios.

Government Incentives

Highly supportive government incentives

Economic challenges to RE development

Green Spread

High economic returns to RE development

Supported Development

- High level of government incentives helps offset difficult economic environment.
- Pace of RE development dependent upon sheltered environment.

Accelerated Development

- High level of government incentives and a favorable economic environment for RE
- The combined support drives accelerated RE development.

Backsliding

- Low level of government incentives and poor economic returns for RE projects.
- Retrenchment of RE development.

This scenario unlikely. Excluded from analysis

Market-Based Development

- Favorable economic environment tempered by minimal incentives.
- Pace of RE development depends on strength of market demand.

Minimal government incentives

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This is a "coupled" scenario analysis[1] allowing for examination of the differential impact of Green Spread and Government Incentives.

"Accelerated Development" Scenario

- High "Green Spread" leads to strong financial returns for RE generation development. Contributing to this spread are high market electric prices driven by high natural gas and carbon prices (due for example to aggressive federal GHG reduction policies) as well as declining costs for RE generation technologies.
- Strong and long-term government incentives are enacted supporting RE development; extensions of the PTC and ITC through 2020 are passed at their current values and today's high REC prices continue through 2020.

"Market-Based Development" Scenario

- High "Green Spread" leads to strong financial returns for RE generation development. Contributing to this spread are high market electric prices driven by high natural gas and carbon prices (due for example to aggressive federal GHG reduction policies) as well as declining costs for RE generation technologies.
- The current PTC and ITC policies remain in place (i.e., they expire at the end of 2008). It is assumed there is no future reauthorization. REC prices decline significantly from today's high values.

"Supported Development" Scenario

- Low "Green Spread" driven by lower market electric prices based on stabilization of natural gas prices and low carbon prices (due for example to continuation of fragmented system of carbon reduction policies across the states rather than a strong federal system) and limited improvements in cost of renewable power generation lead to lower financial returns for RE generation development.
- Strong and long-term government incentives are enacted supporting RE development; extensions of the PTC and ITC through 2020 are passed at their current values and today's high REC prices continue through 2020.

Note: The coupling means scenarios on the same side of the quadrants (see previous slide) have the same input settings. For example, the Accelerated Development and Market-Based Development scenarios, which have high Green Spread have identical settings for natural gas, carbon, wholesale electricity, and retail electricity prices. This allows for the identification of the specific impact of Green Spread vs. Government Incentives.

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The DOER and MTC assumptions for the scenarios are below. They are not forecasts and should not be used outside the scenario framework.

	Supported Development Scenario											
	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Natural Gas Price[1] ($/MMBtu)	$12.80	$11.28	$9.13	$8.04	$8.23	$8.33	$8.78	$9.23	$9.99	$10.65	$11.14	$11.37
Carbon Price[2] ($/ton)	$1.86	$1.86	$1.86	$1.86	$1.86	$3.35	$4.02	$4.82	$5.79	$6.94	$8.33	$10.00
Wholesale Elect. Price[3] (¢/kWh)	10.02	9.28	8.86	7.16	7.56	7.67	7.73	8.18	8.85	9.51	10.13	10.17
Retail Electricity Price[4] (¢/kWh)	19.5	18.4	17.8	15.2	15.9	16.0	16.1	16.8	17.9	18.9	19.8	19.9
REC Price ($/MWh)[5]	51.68	51.68	51.68	51.68	51.68	51.68	51.68	51.68	51.68	51.68	51.68	51.68
PTC/REPI	On (values vary by technology and are provided in the following incentive assumptions slide)											

	Accelerated Development Scenario											
	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Natural Gas Price[1] ($/MMBtu)	$12.80	$15.20	$17.60	$20.00	$20.25	$20.50	$20.75	$21.00	$21.25	$21.50	$21.75	$22.00
Carbon Price[2] ($/ton)	$1.86	$6.24	$10.61	$14.39	$19.37	$23.74	$28.12	$32.49	$36.87	$41.25	$45.62	$50.00
Wholesale Elect. Price[3] (¢/kWh)	10.60	12.81	15.02	17.22	17.67	18.12	18.56	19.01	19.45	19.90	20.34	20.79
Retail Electricity Price[4] (¢/kWh)	20.4	23.6	26.7	29.5	30.1	30.7	31.2	31.8	32.4	32.9	33.5	34.0
REC Price ($/MWh)[5]	51.68	51.68	51.68	51.68	51.68	51.68	51.68	51.68	51.68	51.68	51.68	51.68
PTC/REPI	On (values vary by technology and are provided in the following incentive assumptions slide)											

Sources and Assumptions: All value are in real 2008 dollars.

1. Natural gas prices in the Supported Development scenario begin at current prices, with forecast years based on NCI estimates; in Accelerated Development scenario natural gas price forecast starts at $12.80/MMBTU in 2009 (same as in Supported Development scenario) and then linearly increases to $20.00/MMBTU in 2012, with a slower increase thereafter. NCI assumed a linear increase to $22.00/MMBTU by 2020.
2. Carbon price in Supported Development scenario based on NCI estimates; in Accelerated Development scenario carbon prices start at $1.86 per ton in 2009 (same as in the Supported Development scenario) with a linear increase to $50.00 per ton in 2020.
3. Electricity price in Supported Development scenario calculated with Promod, utilizing the relevant natural gas and carbon price inputs. For Accelerated Development scenario, electricity prices calculated by NCI utilizing relevant natural gas and carbon prices for this scenario, assuming average annual marginal heat rate of 8,200 BTU/kWh and CO_2 emissions of 1,100 lbs/MWh for all years during the forecast. These values are based on the 2005 New England Marginal Emission Rate Analysis.
4. The retail electricity prices are an assessment of retail prices adjusted for consistency with the wholesale electricity prices shown for each scenario.
5. REC prices in the Supported Development and Accelerated Development scenarios remain constant at recent levels (Evolution Markets Monthly Market Update, May 2008).

The DOER and MTC assumptions for the third scenario are below. They are not forecasts and should not be used outside the scenario framework.

	Market-Based Development Scenario											
	2009	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Natural Gas Price[1] ($/MMBtu)	$12.80	$15.20	$17.60	$20.00	$20.25	$20.50	$20.75	$21.00	$21.25	$21.50	$21.75	$22.00
Carbon Price[2] ($/ton)	$1.86	$6.24	$10.61	$14.39	$19.37	$23.74	$28.12	$32.49	$36.87	$41.25	$45.62	$50.00
Wholesale Elect. Price[3] (¢/kWh)	10.60	12.81	15.02	17.22	17.67	18.12	18.56	19.01	19.45	19.90	20.34	20.79
Retail Electricity Price[4] (¢/kWh)	20.4	23.6	26.7	29.5	30.1	30.7	31.2	31.8	32.4	32.9	33.5	34.0
REC Price ($/MWh)[5]	51.68	49.96	48.23	46.51	44.79	43.07	41.34	39.62	37.90	36.18	32.73	31.01
PTC/REPI	off											

Sources and Assumptions: All value are in real 2008 dollars.

1. Natural gas price forecast starts at $12.80/MMBTU in 2009 and then linearly increases to $20.00/MMBTU in 2012, with a slower increase thereafter. NCI assumed a linear increase to $22.00/MMBTU by 2020.
2. Carbon prices start at $1.86 per ton in 2009 (same as in Supported Development scenario) with a linear increase to $50.00 per ton in 2020.
3. Electricity prices calculated by NCI utilizing relevant natural gas and carbon prices for this scenario, assuming average annual marginal heat rate of 8,200 BTU/kWh and CO_2 emissions of 1,100 lbs/MWh for all years during the forecast. These values are based on the 2005 New England Marginal Emission Rate Analysis.
4. The retail electricity prices are an assessment of retail prices adjusted for consistency with the wholesale electricity prices shown for each scenario.
5. REC prices decline 40% from recent levels (Evolution Markets Monthly Market Update, May 2008) by 2020.

Financial assumptions vary by technology type and maturity.

	Wind			Biomass			Hydro	Ocean	
	Community[3]	On shore	Off shore	Co-fire	Direct Combustion	Gasifi-cation	Small River	Tidal	Wave
Cost of Equity[1] (%)	13	17	15	14	17	17	17	15	15
Cost of Debt[1] (%)	10	10	10	0	8	12	8	12	12
Equity[1] (%)	40	40	50	100	40	50	40	50	50
Debt[1] (%)	60	60	50	0	60	50	60	50	50
WACC[2] (%)	11.20	10.33	10.44	14.00	9.62	12.03	9.50	11.03	11.03
Length of Debt Repayment[1] (yr)	15	15	15	15	15	15	15	15	15
Federal Income Tax (%)	N/A	35	35	35	35	35	35	35	35
State Income Tax (%)	N/A	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5
Effective Tax Rate (%)	N/A	41.2	41.2	41.2	41.2	41.2	41.2	41.2	41.2

Sources and Assumptions: All value are in real 2008 dollars.

1. Based on current & proposed projects in the U.S. and Canada. More mature technologies are assumed to use more debt at a lower rate and to require less insurance. Co-fire projects assumed to utilize internal financing.
2. WACC is the weighted average of the cost of equity, cost of debt, % equity and % debt of the project. It is used as the discount rate for the project.
3. Community wind is assumed to be owned by a state or local government, making it eligible for the REPI, not the PTC, and exempt from taxes.

Financial assumptions vary by technology type and maturity.

	Wind			Biomass			Hydro	Ocean	
	Community[3]	On shore	Off shore	Co-fire	Direct Combustion	Gasifi-cation	Small River	Tidal	Wave
Property Tax (% of system book value)	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Insurance Cost[1] (% of Fixed O&M cost)	0.15	0.15	0.15	0.5	0.5	0.5	0.5	2.0	1.5
Land Lease Charges[2] (% of gross revenue)	3	3	2	0	0	0	0	0	0

Sources and Assumptions: All value are in real 2008 dollars.

1. LBNL reports 0.15% as a standard insurance assumption for wind projects. For Ocean, 2% and 1.5% are taken from EPRI reports.
2. Land lease charges assumed to apply only to wind projects, as water-based systems are assumed to not lease land, and biomass land acquisition costs are assumed included in capital costs. For Onshore wind, LBNL assumed 3% of revenue is attributable to land costs and lists an acceptable range of 2-5%. Offshore wind is assumed to be 2%, the lower end of the range, as an investor would be leasing from the government.
3. Community wind is assumed to be owned by a state or local government, making it eligible for the REPI, not the PTC, and exempt from taxes.

Federal and State incentives vary by technology and system ownership type.

	Wind			Biomass			Hydro	Ocean	
	Community (0.6/1.5MW)	On shore	Off shore	Co-fire	Direct Combustion	Gasifi-cation	Small River	Tidal	Wave
Rebate[1] (% of system cost)	43/19	N/A	N/A	N/A	0.09	0.09	N/A	N/A	N/A
Performance-based Incentive[2] (¢/kWh)	N/A	N/A	N/A	N/A	N/A	N/A	.018	N/A	N/A
% Installed System used for tax depreciation	100%	100%	100%	100%	100%	100%	100%	100%	100%
Property Tax Exemption[3]	100%	100%	100%	0%	0%	0%	100%	0%	0%
PTC rate (¢/kWh)	N/A	0.02	0.02	0.01	0.01	0.01	0.01	N/A	N/A
PTC duration (years)	N/A	10	10	10	10	10	10	N/A	N/A
REPI rate (¢/kWh)	0.02	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
REPI duration (years)	10	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Sources and Assumptions: All value are in real 2008 dollars.

1. Rebate reflects MTC's Community Wind grant and Large On-site Renewables grant (LORI) for community wind and biomass technologies, respectively. The max funding per applicant for each program divided by the installed system cost results in the % of system cost rebate.
2. Section 242 of Energy Policy Act of 2005 established a performance-based incentive of 1.8 cents for each incremental kWh produced at a site after redevelopment/addition of new generating capacity at existing dams or conduits.
3. Massachusetts provides a property tax exemption incentive for Wind and Hydro systems.
4. "N/A" implies that the specific incentive is not applicable to that technology or ownership type. For example, community wind projects are assumed to be owned by state/local government, which is eligible for the REPI, not PTC.

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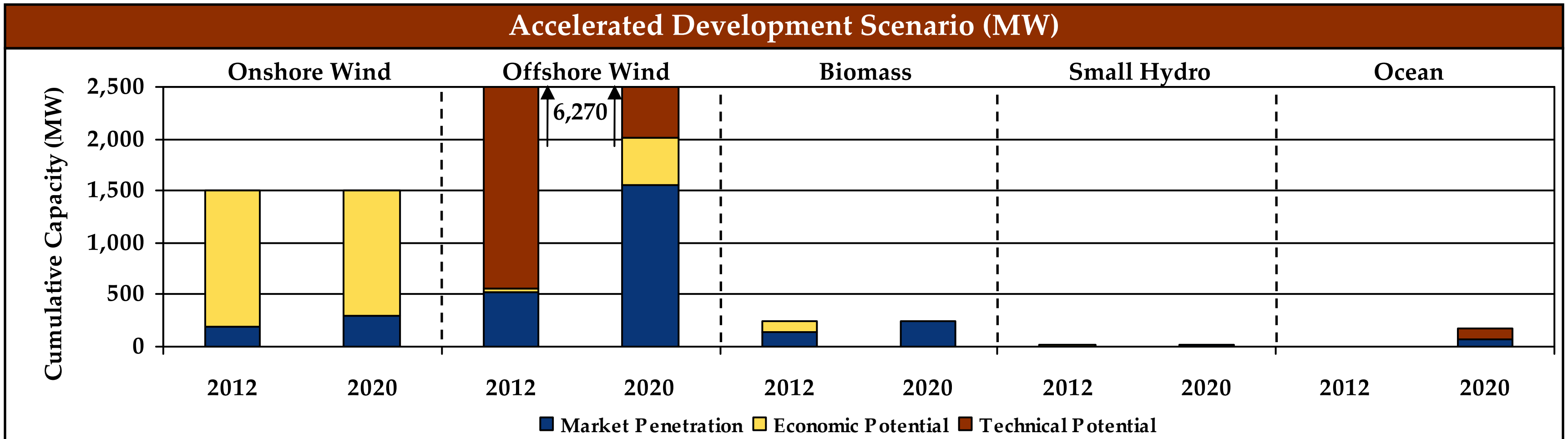
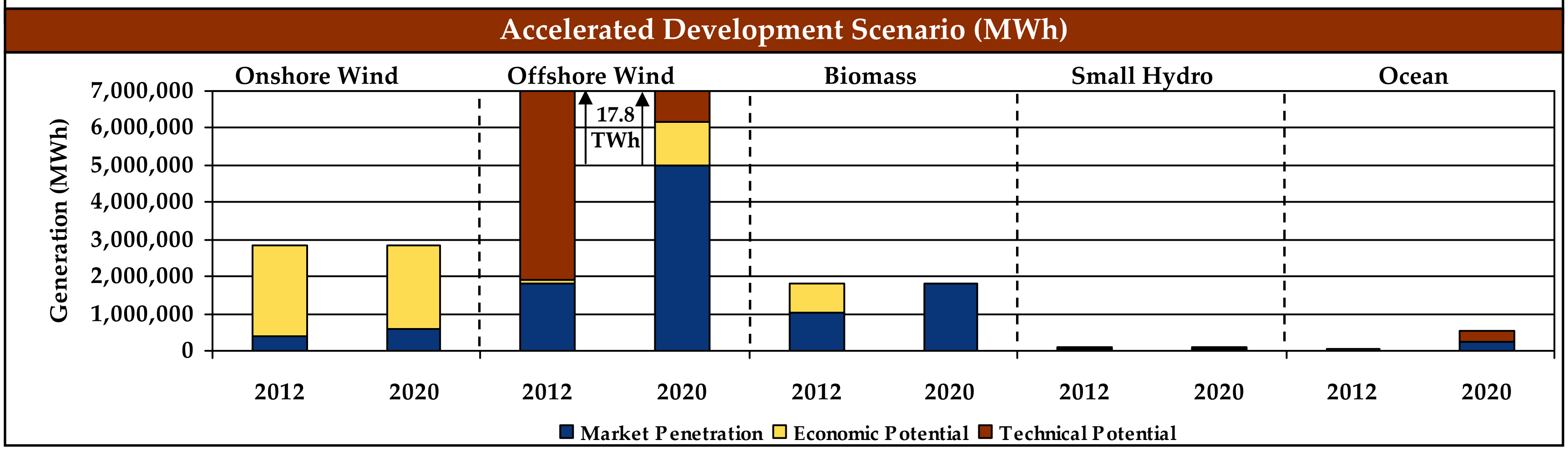
Under the Accelerated Development scenario, wind and biomass have the most significant development potential.





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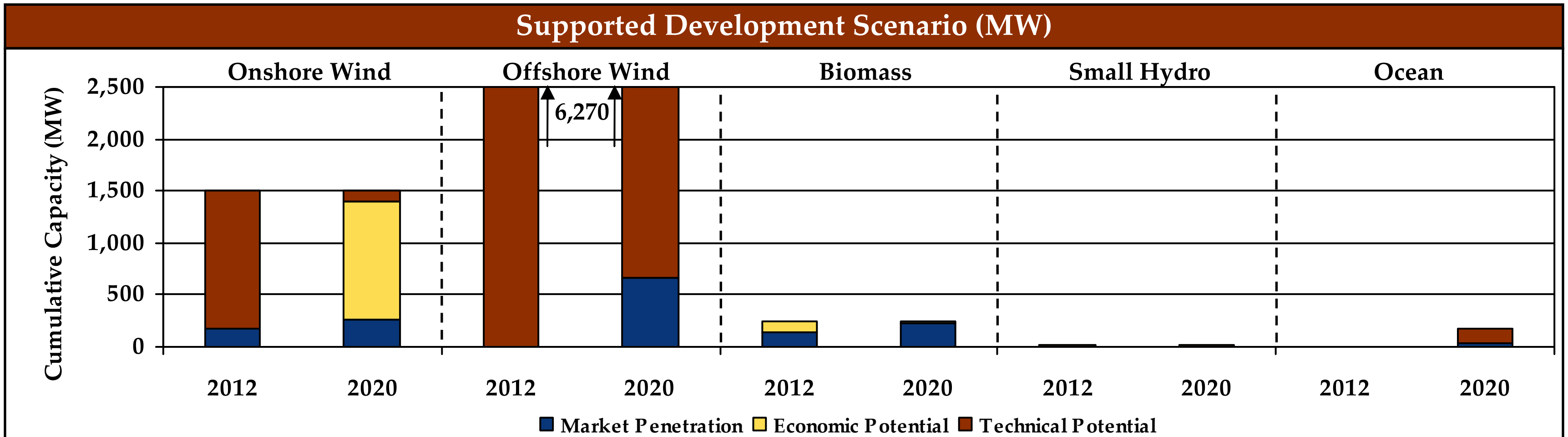
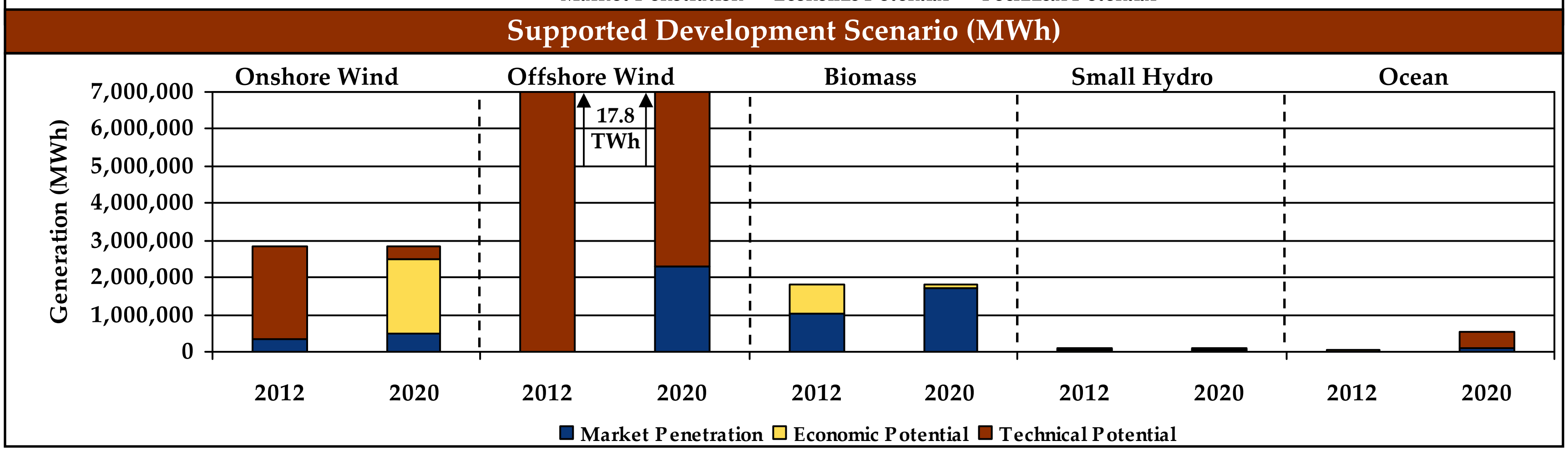
Under the Supported Development scenario generally shows the least amount of development potential.





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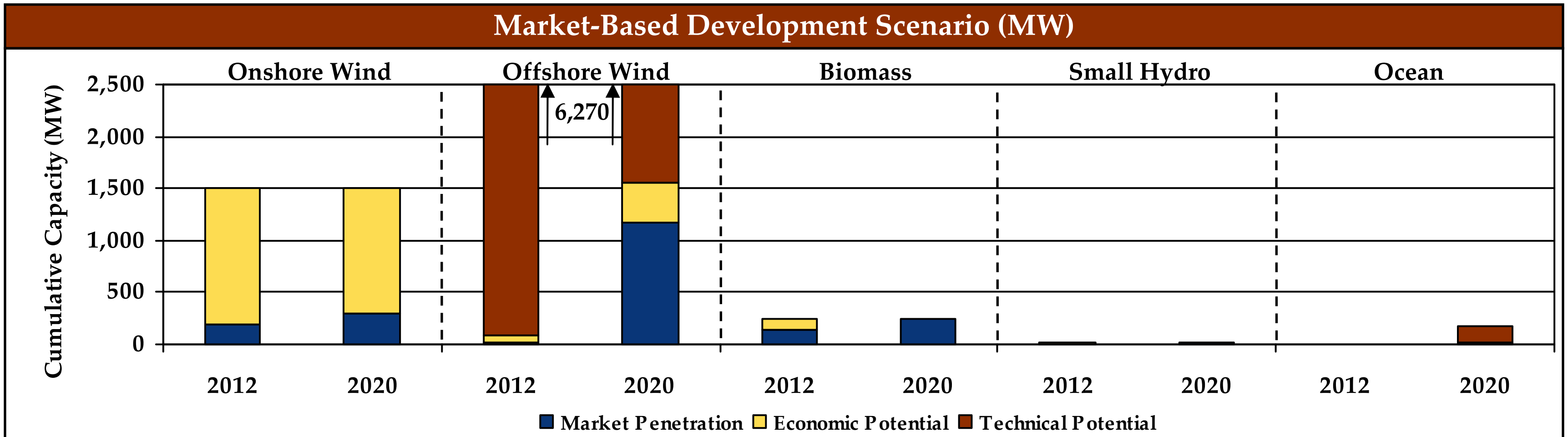
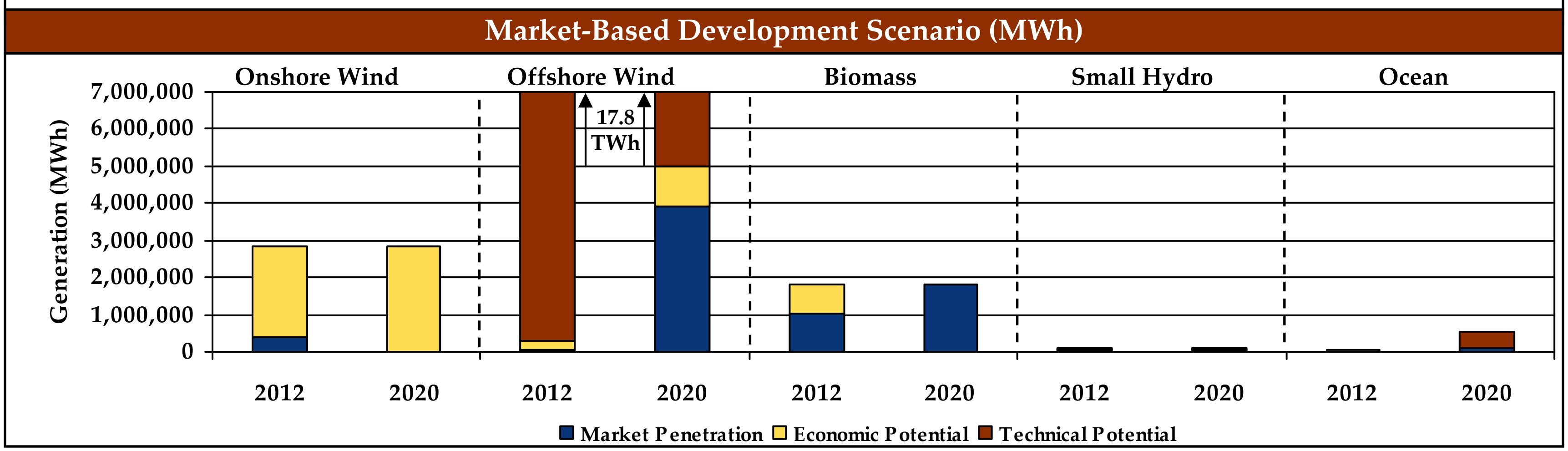
Under the Market-Based Development scenario, offshore wind shows the most development potential.





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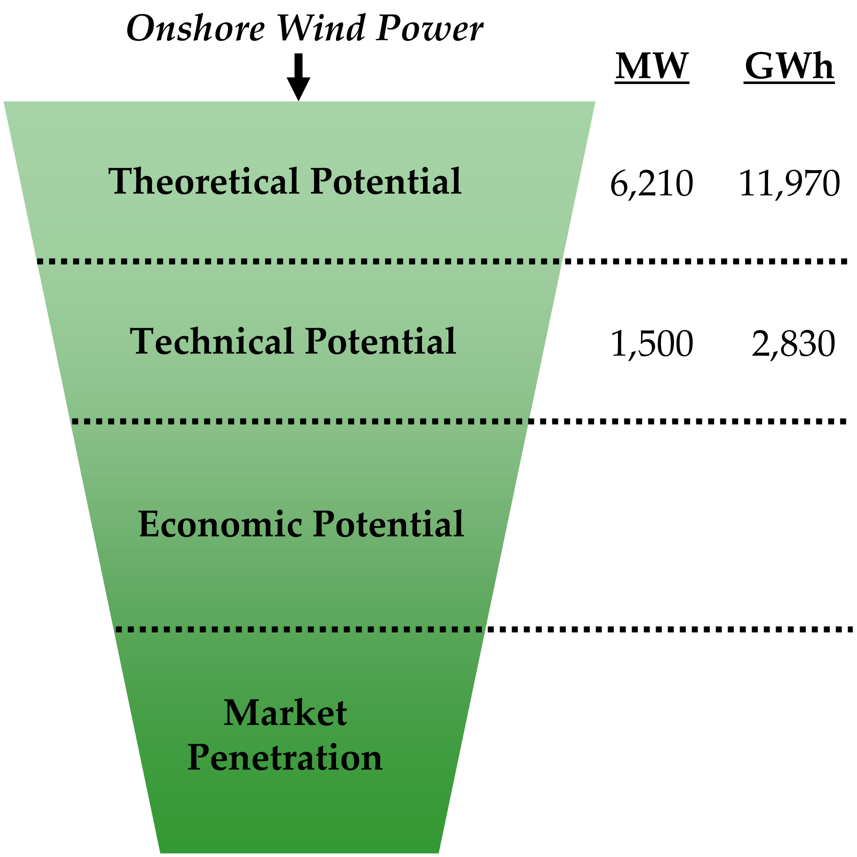
There is 1,500 MW of technical potential for onshore wind, based on the wind resource, land exclusions, policy restraints, and siting issues.



- Theoretical potential:
  - This is the dependable capacity based on summer wind patterns in MA from *Technical Assessment of Onshore and Offshore Wind Generation Potential in New England*, Levitan and Associates, May 2007.
  - Methodology used two screening criteria for the state land area, which was divided into 200 m^2 blocks. Each included block had to have a Class 3 wind regime or better at 50 m hub height and a population density less than 3,787 people/square mile (the density of Hull, MA in 2000).
  - Assumptions included use of GE 1.5 MW turbines and spacing between turbines of 280 m.
- Technical potential:
  - The potential is the sum of several factors:
  - ~1,400 MW in technical potential from the Elliot, D.L., et al., *Assessment of the Available Windy Land Area and Wind Energy Potential in the Contiguous United States*, Prepared by Battelle for U.S. DOE, August 1991. It is for wind regimes of Class 3 and above and the calculations assume 50 m.hub height with 10 x turbine diameter (D) by 5 x D spacing, 25% efficiency, and 25% losses. The severe land use and environmental exclusions scenario was used.
  - ~100 MW in Class 2 wind sites identified in MTC's *Community Wind Sites Database.*

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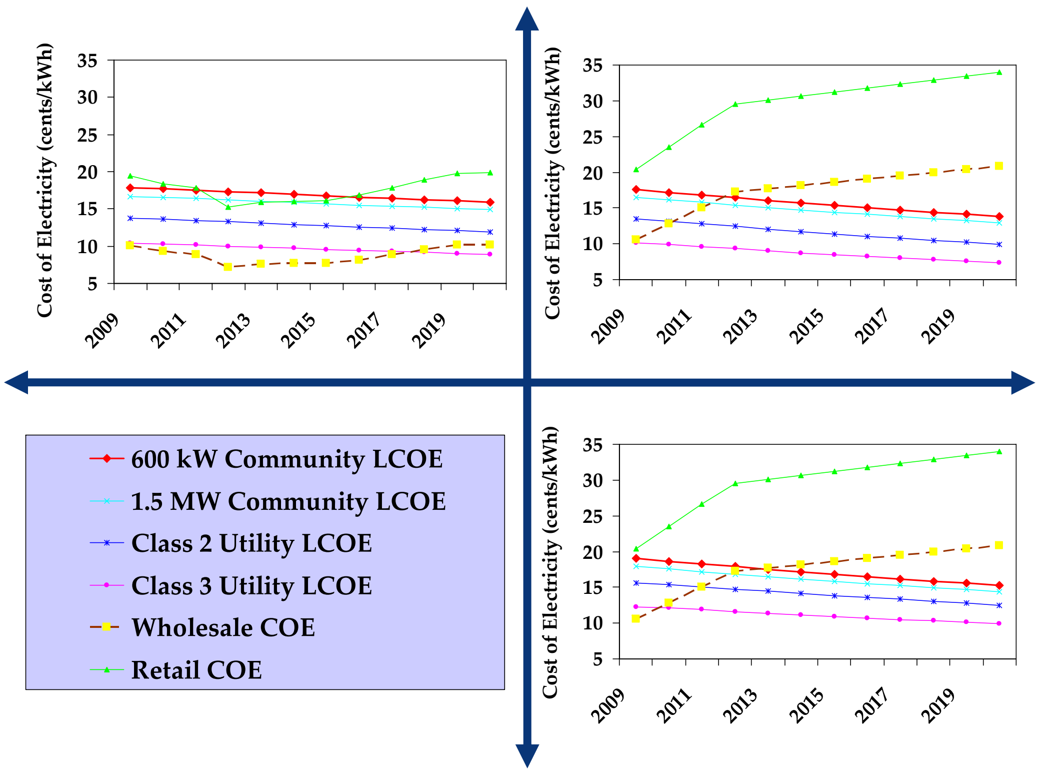
The economics of onshore wind are favorable under the Accelerated Development and Market-Based Development scenarios.

Supported Development ***Accelerated Development***

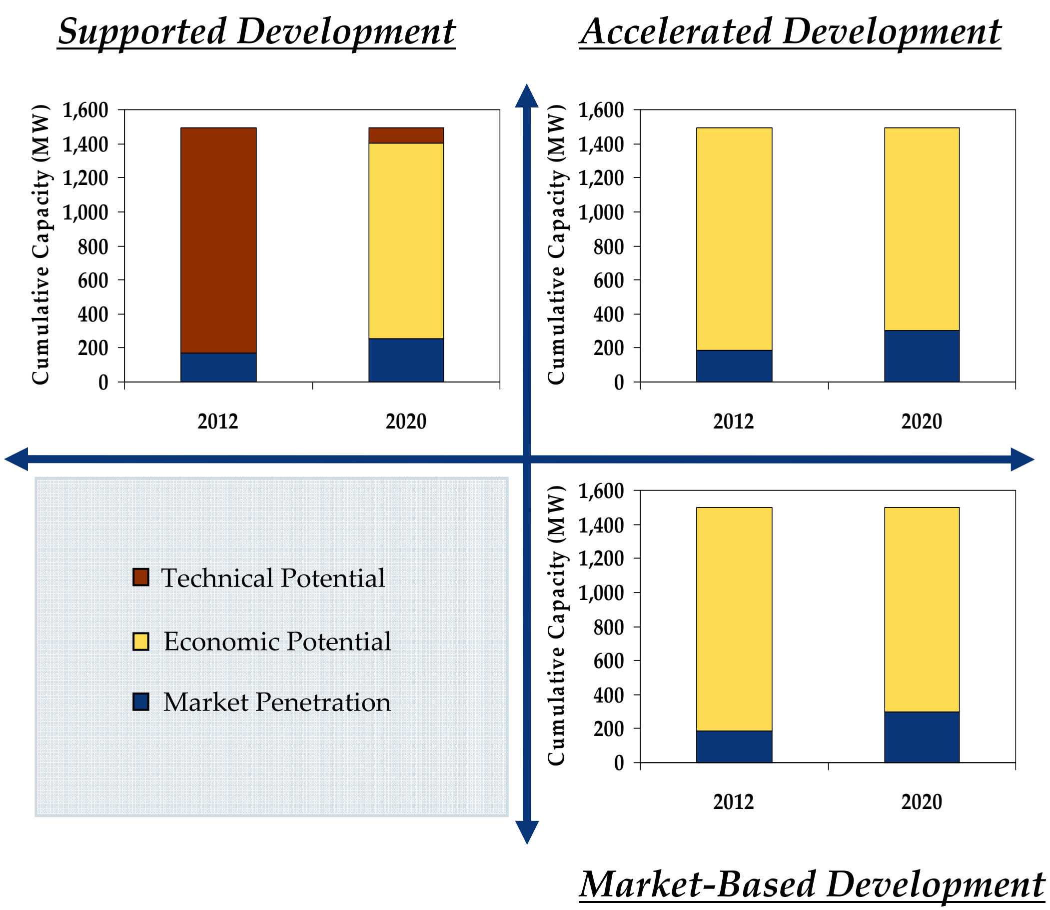


Market-Based Development

Key Assumptions & Observations

- The minimum project size considered is 500 kW. Currently, projects less than that make up less than 4% of MTC's *Wind Project Pipeline Database*.
- For economic analysis, four types of projects were modeled:
  - A single 600 kW turbine community-scale project representing projects with less than 5 turbines (500 kW – 1 MW)
  - A single 1.5 MW turbine community-scale project representing projects with less than 5 turbines (1+ MW)
  - 5 x 1.5 MW turbines in 6.0-6.8 m/s wind at 65 meter height representing projects with 5+ turbines in Class 2 wind
  - 5 x 1.5 MW turbines in greater than 6.8 m/s wind at 65 meter height representing projects with 5+ turbines in Class 3 wind
- For utility-scale projects, project economic viability was based on a comparison of LCOE and wholesale market electricity cost while community wind projects were compared to the retail electricity rates.
- In the Accelerated and Market-Based Development scenarios, community wind projects are economic driven by the high retail cost of electricity.

In all three scenarios Onshore wind has a market penetration over 168 MW by 2012 and over 256 MW by 2020.



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Key Assumptions & Observations

- The graphs represent a combination of community-scale and utility-scale projects.
- MTC's *Wind Project Pipeline Database* was used to determine current projects that fall into the four types of projects. Projects in the database that are already completed (~5MW) or classified as Phase IV – Design and Construction (~95 MW) are assumed to be fully installed by 2012.
- MTC's *Community Wind Sites Database* was used to identify potential future utility-scale projects with Class 2 or Class 3 winds. Relative probabilities for the utility-scale potential sites were assigned based on information provided regarding the site's technical characteristics and used to develop an estimate of future projects.
- An estimate of the potential future community-scale sites was developed by factoring out of the state technical potential current and historical projects as well as the identified future utility-scale sites.

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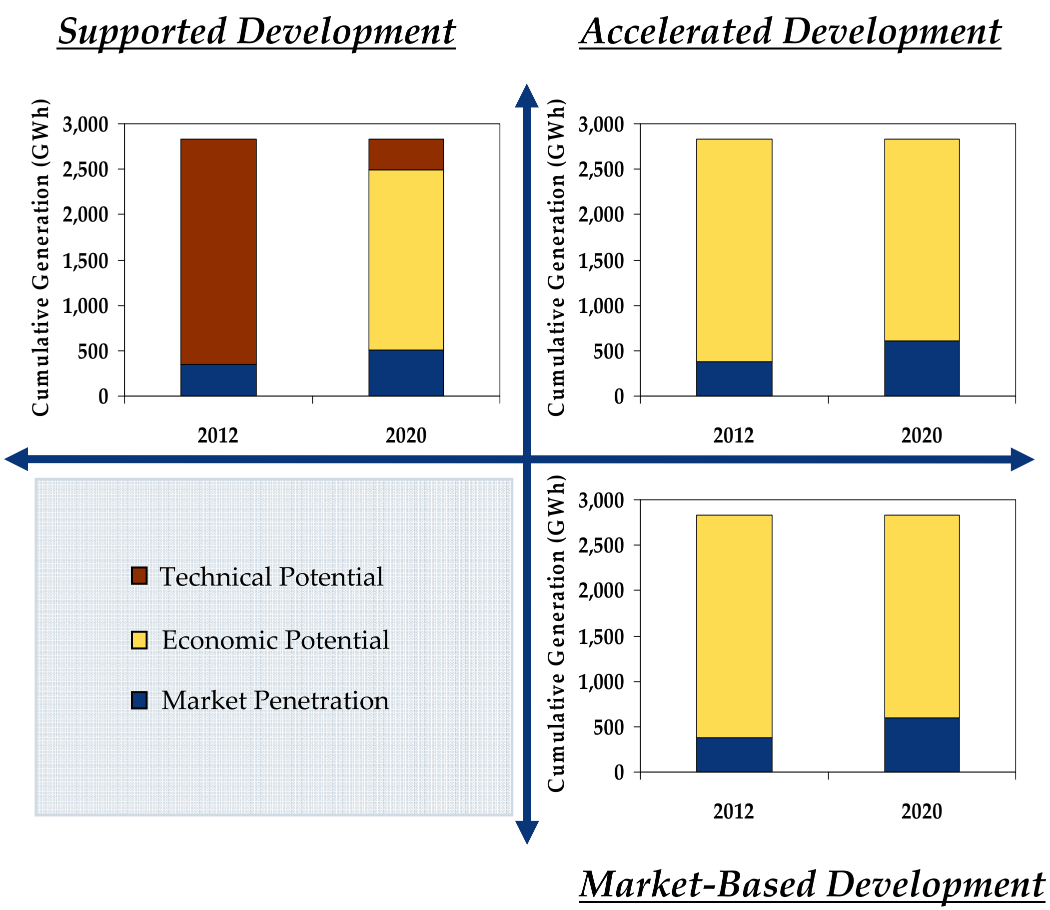
In all three scenarios Onshore wind has a market penetration over 340 GWh by 2012 and over 510 GWh by 2020 (continued).



Key Assumptions & Observations

- A market diffusion curve was used to estimate the time of entry of economic projects into the market. NCI analyzed mature wind markets across the world to estimate the time it takes to move from 10% diffusion to 90%. Based on this information and the challenges of onshore wind in MA (NIMBY, challenging geographies in areas of the best wind resources, etc), NCI used a time of 25 years for utility-scale projects and 36 years for community-scale projects.
- On both the onshore MW and GWh slides, no economic potential is shown for onshore wind in 2012 because market penetration exceeds economic potential.
- The reasons behind this are that Phase IV – Design and Construction in the *Wind Project Pipeline Database* projects are assumed to be fully installed by 2012 independent of economics and that although community wind projects are not economically viable in 2012, they had been in previous years and had therefore already penetrated the market.

Note: NCI analyzed a series of scenarios based on DOER and MTC assumptions that describe different hypothetical states of the world. The scenarios do not represent a NCI prediction or forecast, and they are not meant for predicting or bounding the most likely future.

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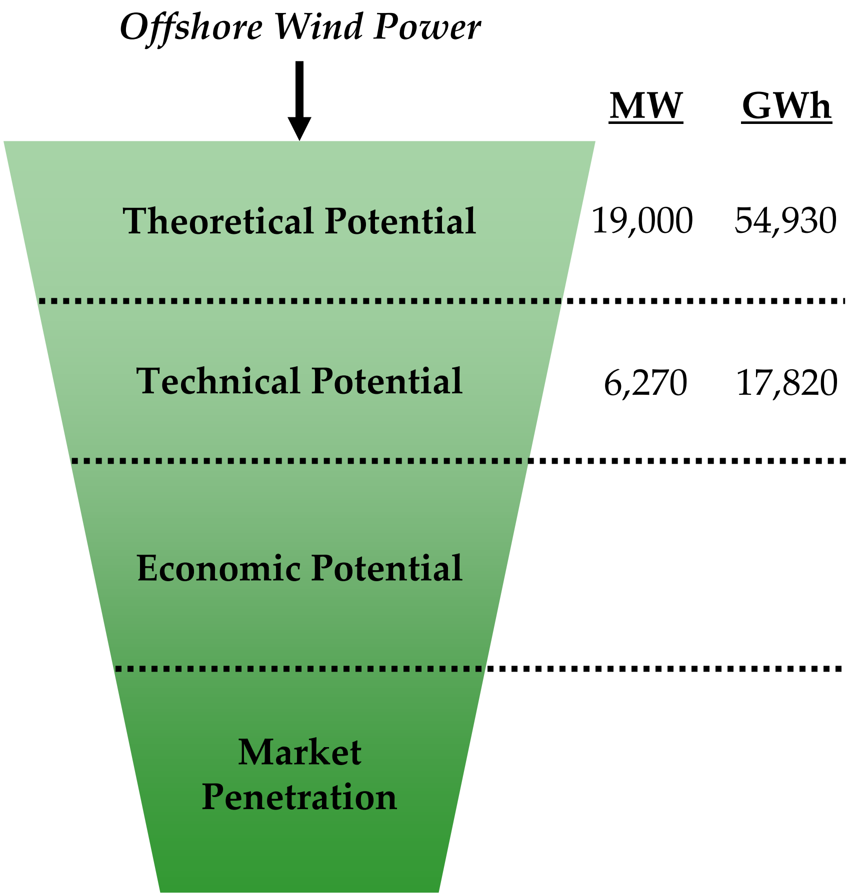
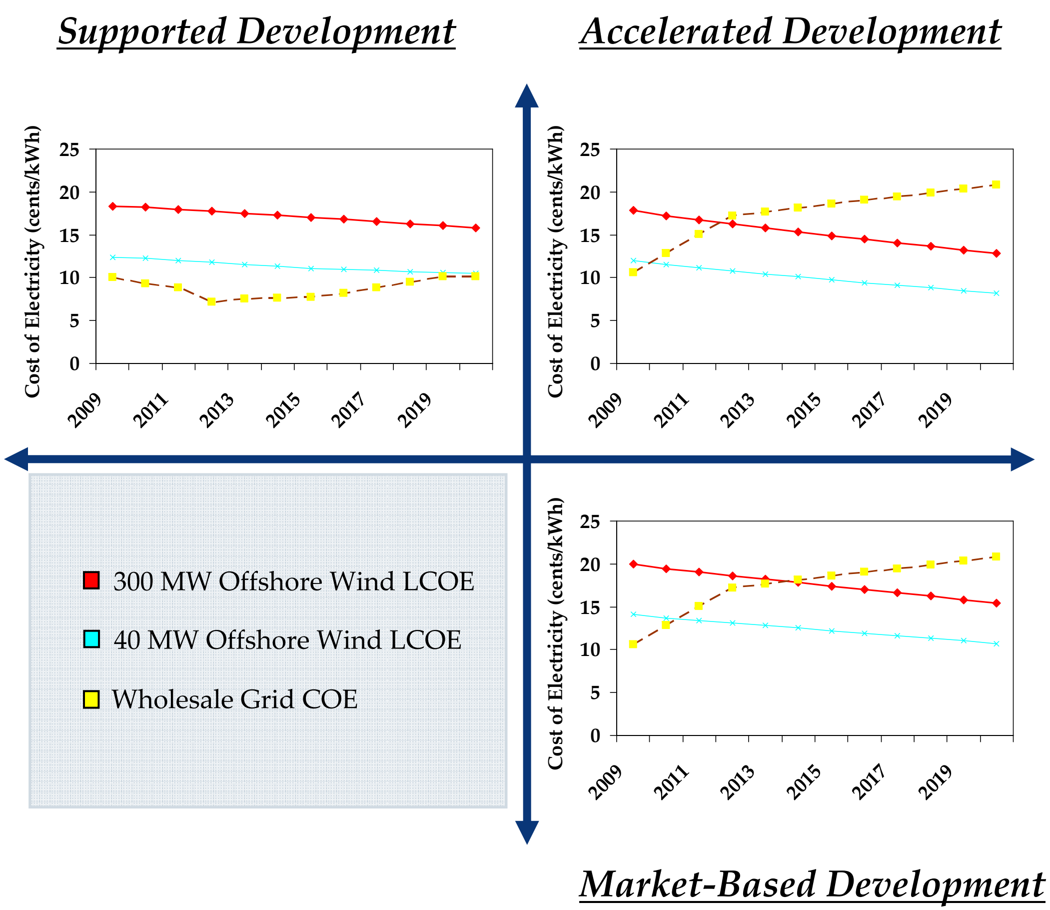
The MA offshore wind technical potential is ~6,270 MW, based on the resource, land exclusions, policy restraints, and siting issues.



- Theoretical potential:
  - Potential comes from Rogers, Anthony L., et al., *A Fresh Look at Offshore Wind Opportunities in Massachusetts*. University of Massachusetts at Amherst, May 2000.
  - Estimate assumptions include the use of 1.65 MW turbines with a 66 m rotor diameter in waters less than 60 feet in depth[1] and an average capacity factor of 33%.
- Technical potential:
  - The values are derived through the application of a 67% exclusion factor to convert theoretical to technical potential.
  - The factor, which is described in Musial, Walt, *Offshore Wind Energy Potential in the United States*, Presentation at Wind Powering America – Annual State Summit, Evergreen, Colorado, May 19, 2005, accounts for exclusions based on avian and marine mammal habitats, other restricted habitats, view shed, and shipping routes. The factor was proposed for 5-20 nm and a 100% exclusion factor was proposed for inside 5 nm, but 67% was used because projects are already in development inside 5 nm.

1. The estimate does not include the immense deep sea wind resource (DOE estimates that New England has 130.6 GW theoretical potential between 60 and 900 meters in depth according to Musial 2005), which developers, regulators, and academics indicate will not be technically accessible until after 2020 given the state of current technologies.

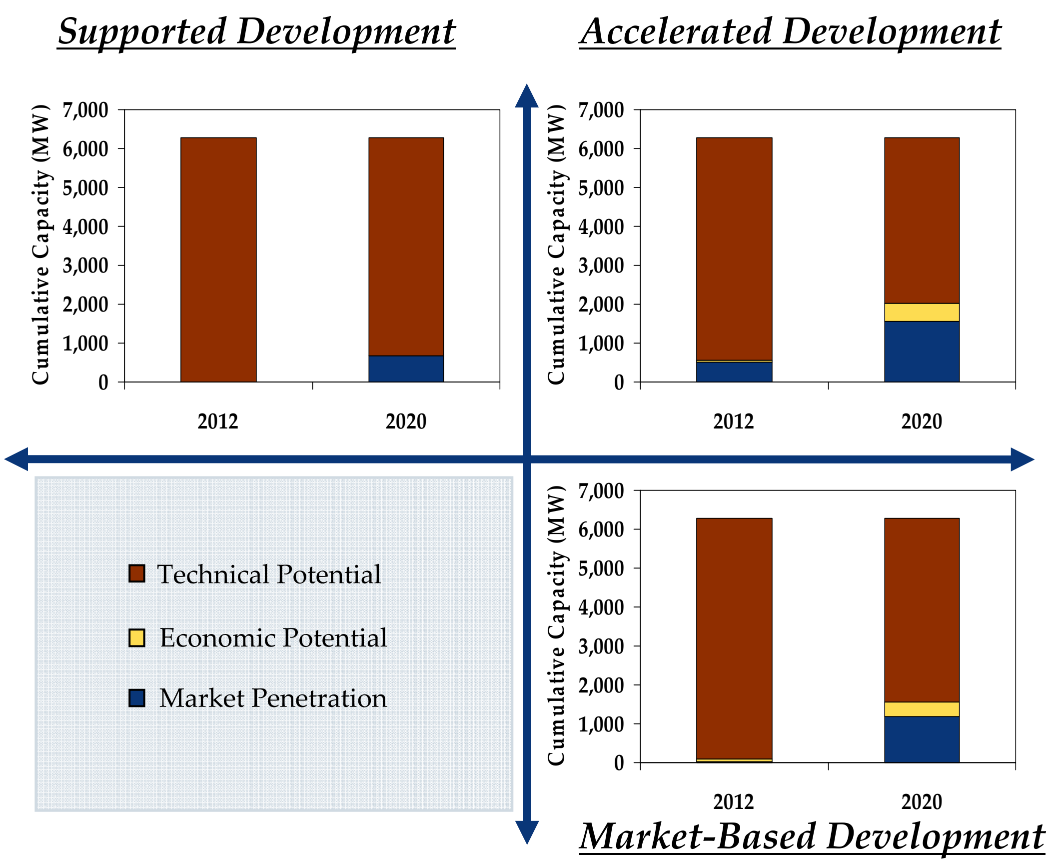
The LCOEs of offshore wind dip below wholesale electric prices in the Accelerated Development and Market-Based Development scenarios.



Key Assumptions & Observations

- Project economics were analyzed for eleven offshore wind sites identified in the literature and through discussions with developers, regulators, and researchers. Economic viability was based on a comparison of LCOE and wholesale market electricity rates.
- The results of two representative projects are shown on the left: one of 300 MW and one of 40 MW.
- Driven by lower installed costs, which are in turn largely driven by closer proximity to shore, the LCOEs for the 40 MW projects are smaller in all three scenarios.
- The LCOEs for both project sizes drop below the wholesale price by 2012 under the Accelerated Development scenario and 2014 under the Market-Based Development scenario.
- Although the Supported Development scenario LCOEs are lower than in the Market-Based Development scenario, the lower wholesale electric rates result in unfavorable project economics.

Offshore wind reaches maximums under Accelerated Development scenario of 520 MW by 2012 and 1,550 MW by 2020.



Note: NCI analyzed a series of scenarios based on DOER and MTC assumptions that describe different hypothetical states of the world. The scenarios do not represent a NCI prediction or forecast, and they are not meant for predicting or bounding the most likely future.

1. Buzzards Bay project is estimated to be 150 MW based on interviews of regulators and consultants.

Key Assumptions & Observations

- Based on conversations with developers, regulators, and researchers, it is clear that deep sea projects will not occur until after 2020, so the technical potential here is limited to waters less than 60 meters.
- It is assumed that the four projects currently proposed (Cape Wind, Buzzards Bay[1], Hull, and South of Tuckernuck Island) will be implemented regardless of economic conditions by 2020. The timing of their entry into the market is adjusted based on economic conditions under the three scenarios. There is potential for further delays in the commissioning of these projects should major litigation occur.
- In the Supported Development scenario projects do not become economic, so it is assumed they are developed at a loss.
- Once the federal permitting process is finalized by the Minerals Management Service (slated for the end of 2008) and the Oceans Management Plan (scheduled for completion in 2009) clarifies the situation for projects in state waters, the average project development duration is expected to be 5 years.

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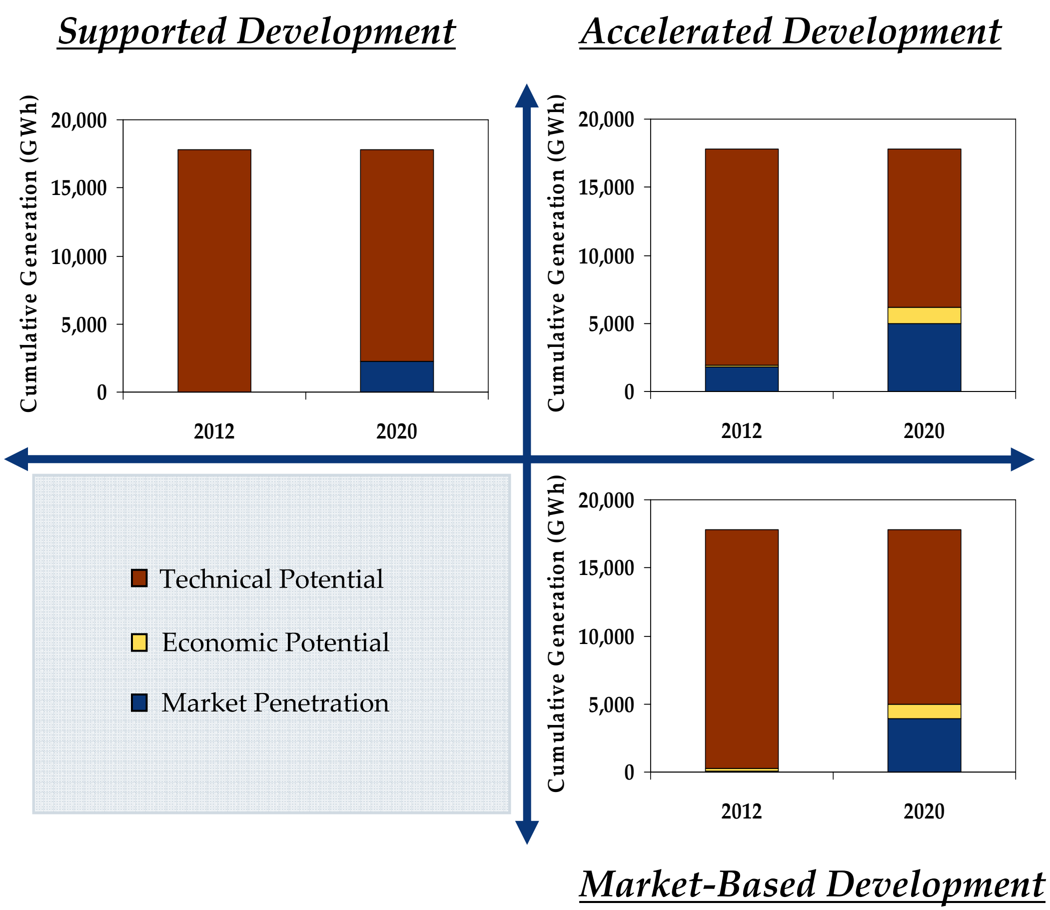
Offshore wind reaches maximums under Accelerated Development scenario of 1,800 GWh by 2012 and 4,990 by 2020 (continued).

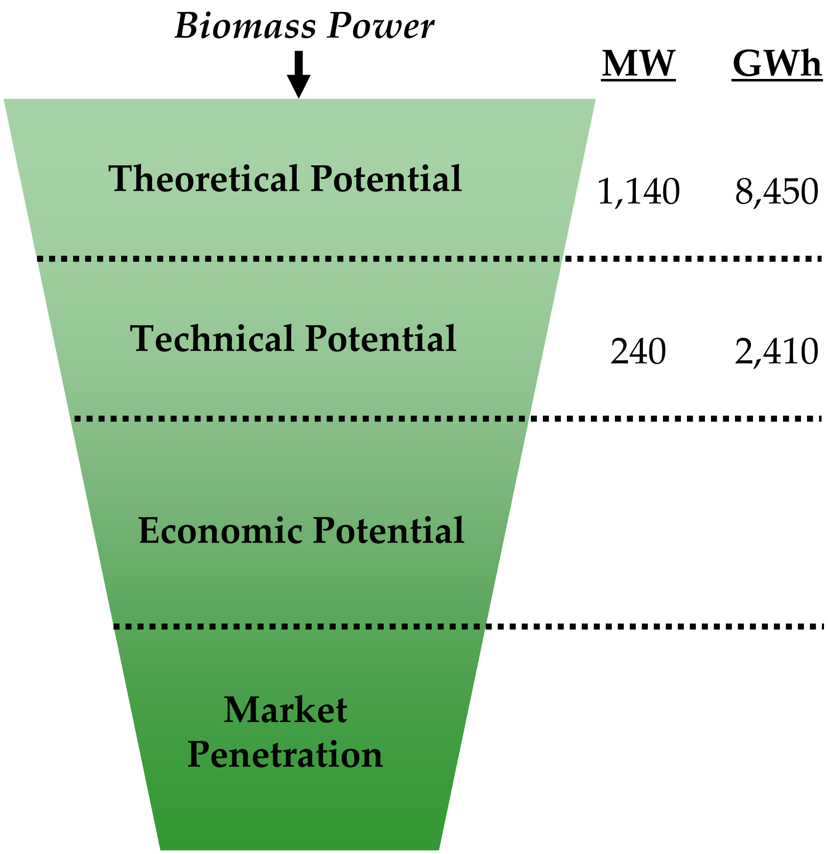


Note: NCI analyzed a series of scenarios based on DOER and MTC assumptions that describe different hypothetical states of the world. The scenarios do not represent a NCI prediction or forecast, and they are not meant for predicting or bounding the most likely future.

Key Assumptions & Observations

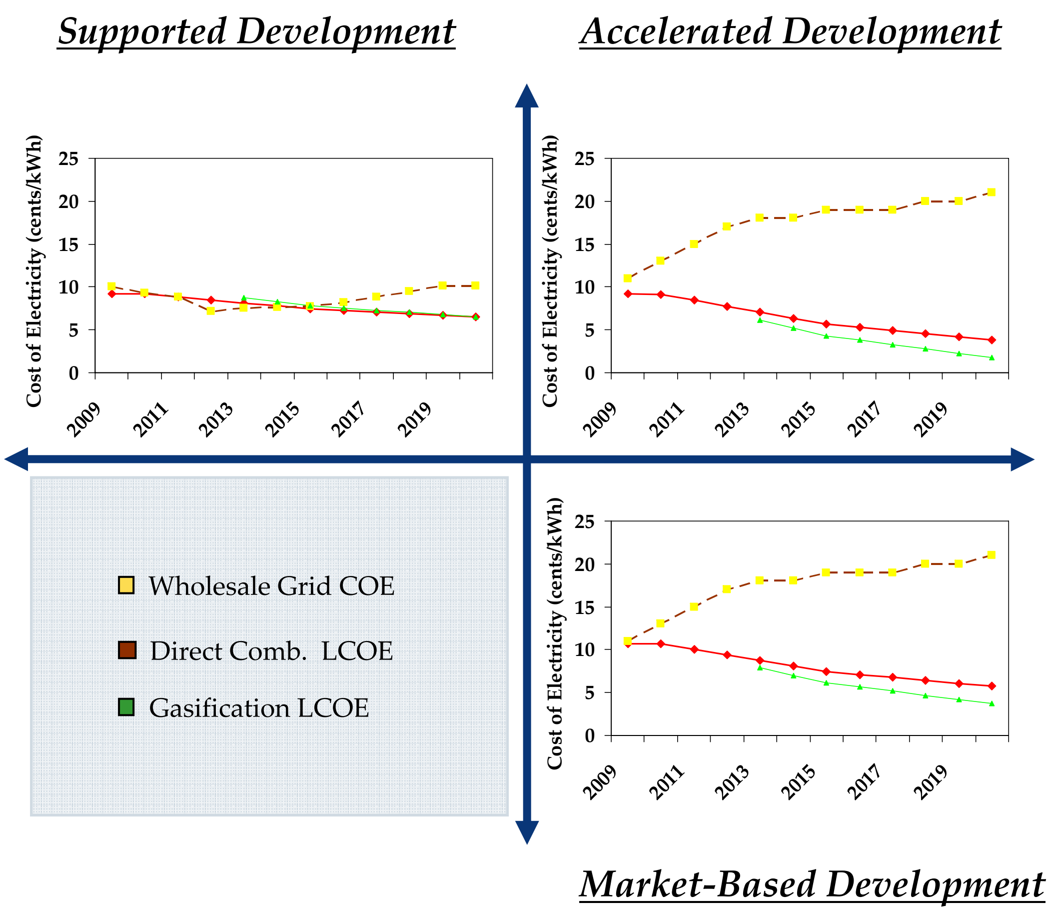
- It is assumed that the 11 identified sites represent the only economically viable sites for offshore wind through 2020 after interviews confirmed that no entity has performed a comprehensive mapping of potential sites in state or federal waters. These sites include:
  - The four currently proposed projects (Cape Wind, Buzzards Bay, Hull, and South of Tuckernuck Island) as identified through interviews,
  - Four alternatives to Cape Wind were retrieved from the Minerals Management Service's *Cape Wind Energy Project Draft EIS* (projects located on or off of Cape Ann, Monomoy Shoals, Nantucket Shoals, and Phelps Bank), and
  - Three sites identified by the developer Winergy (projects located on or off Davis Bank, Truro, Gloucester) were provided through an interview.

There is ~ 240 MW of technical potential for biomass power in Massachusetts.



- Theoretical potential:
  - Includes materials available in 5 "core" counties and 14 "buffer" counties per INRS 1/07 Biomass Availability Analysis; plus amounts for all MA per Fallon & Breger 1/02 study “The Woody Biomass Supply in MA” and the Spring 2008 Advanced Biofuels Task Force Report, as adjusted for amounts already included in Core Counties and the two overlapping MA counties in Buffer counties.
  - Ag residue amounts per INRS 1/07 Biomass Availability Analysis.
  - Energy crops includes first two scenarios from 1/08 Biomass Energy Crops report: 20% of farmland converted and idle farmland put into use (but not third scenario, forestland conversion).
- Technical potential:
  - With respect to logging residue, ag residue and land clearing amounts, NCI estimates 10% loss of theoretical potential due to collection and transportation losses.
  - Primary and secondary forest residues assumed to remain in current uses and unavailable for additional biomass power.
  - Assumes 50% and 60% availability of energy crops and urban wood residue, respectively, reflecting issues surrounding conversion of farmland, collection of urban wastes and C&D contamination.
  - Assume 10% of net forest growth is captured.

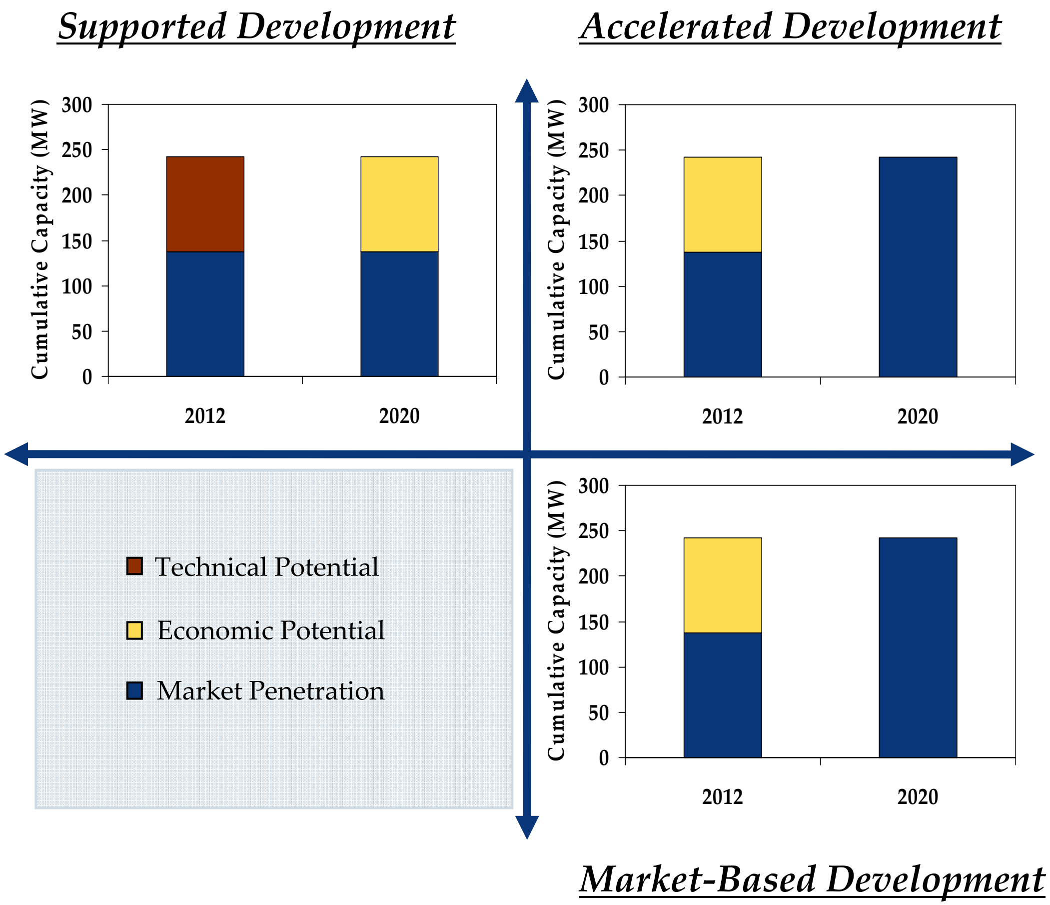
Biomass direct combustion and gasification are highly economical in the high "green spread" scenarios.



Key Assumptions & Observations

- In high government incentives scenarios (i.e., the Accelerated and Supported Development scenarios), available incentives include accelerated depreciation, PTC (10 years, 0.10 cents/kWh), cogen credit and RECs.
- Gasification technology is assumed to not become ready for commercial deployment until 2013.
- Higher cost of financing and reduced available leverage for gasification reflect relative immaturity of the technology.
- Gasification becomes increasingly cost effective over time as the technology matures. The degree, and timeline, of gasification cost reductions is highly uncertain, however, in relation to more mature direct combustion technology.
- Biomass is very economical in both high green spread scenarios due to high market power prices.

No more than the existing pipeline is likely to be implemented by 2012, with additional ~100 MW possible by 2020 in certain scenarios.



Note: NCI analyzed a series of scenarios based on DOER and MTC assumptions that describe different hypothetical states of the world. The scenarios do not represent a NCI prediction or forecast, and they are not meant for predicting or bounding the most likely future.

Key Assumptions & Observations

- Analysis assumes, per DOER/MTC guidance, that approximately 138 MW of biomass projects currently in development pipeline become operational.
- Analysis assumes resources are available within MA (and not exported) for biomass power generation.
- Analysis does not take into account potential use of biomass for pelletizing or other space heating uses
- In Accelerated Development and Market-Based Development scenarios, 138 MW are operational by 2012 and the remainder of technical potential utilized by 2020.
- In these scenarios the high green spread drives adoption; long development timeline, however, limits facilities that may be deployed by 2012.
- In Supported scenario only current project pipeline is implemented

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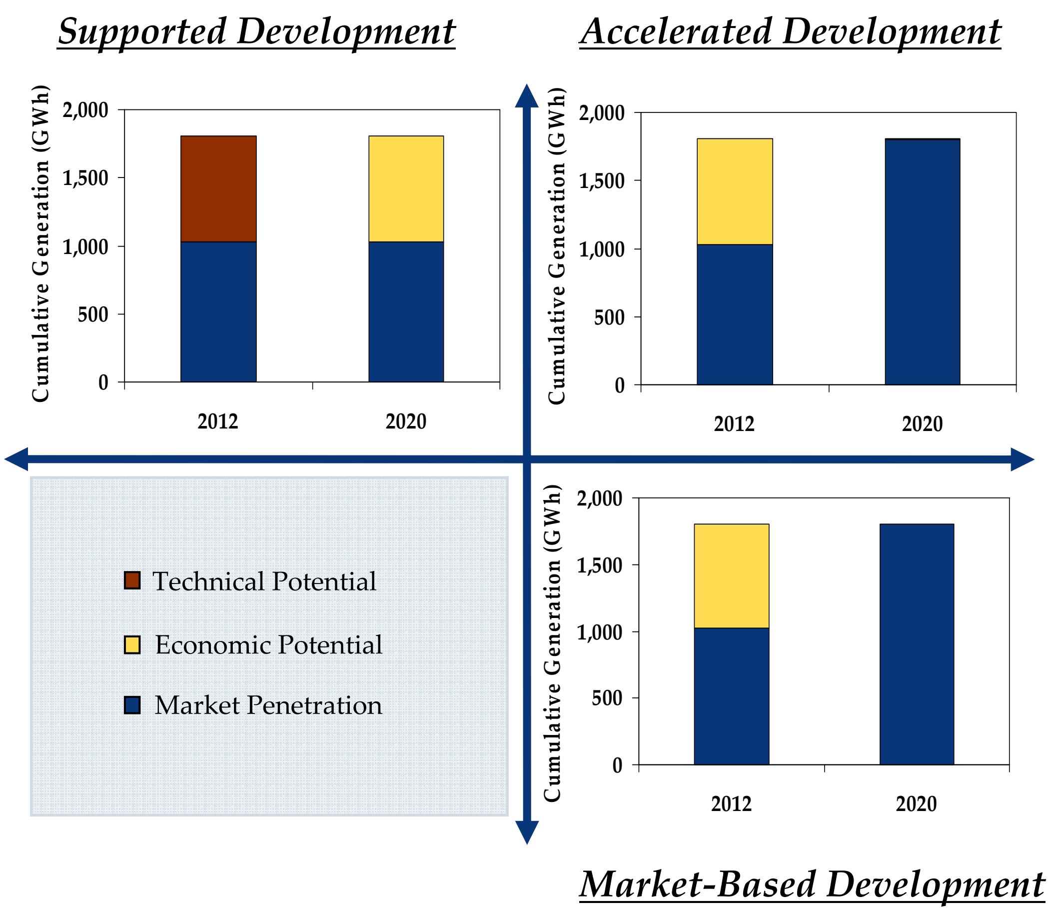
High capacity factors for biomass facilities leads to high GWh potential relative to other technologies.



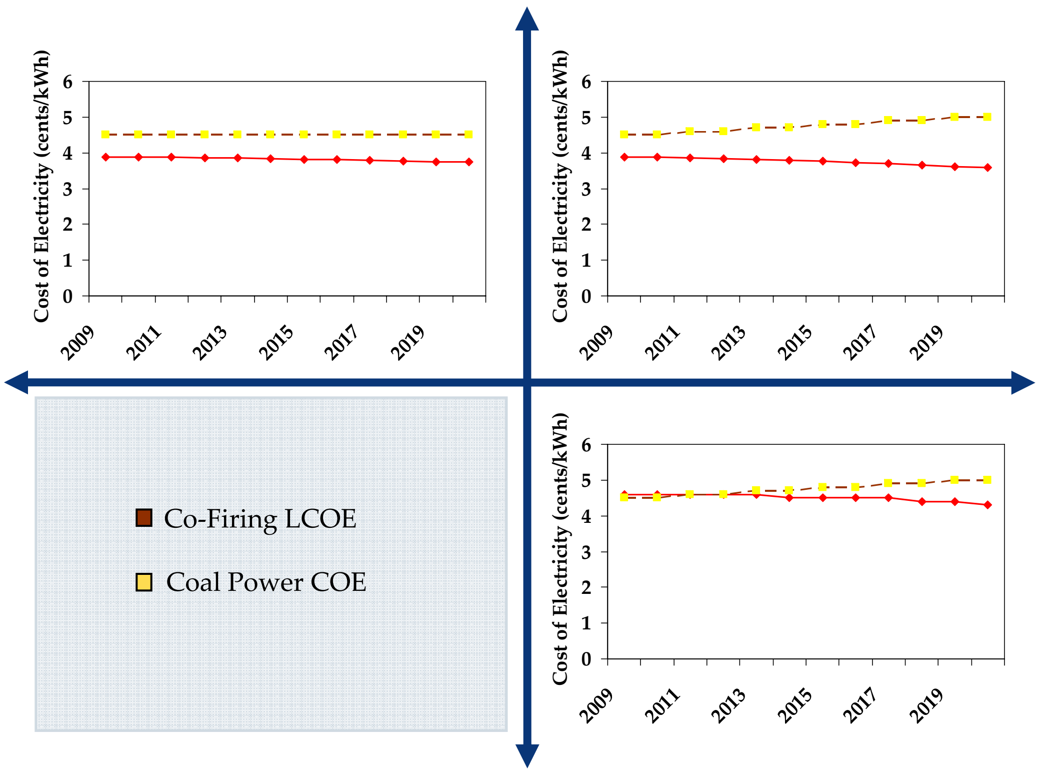
Key Assumptions & Observations

- By 2012, the only facilities that are assumed to become operational are the three currently in development, all of which utilize direct combustion.
- By 2020, additional facilities may be developed which may utilize either direct combustion or gasification.
- Over 1,800 GWh market penetration by 2020 in the Accelerated Development and Market-Based Development scenarios.
- Analysis assumes 85% capacity factor and 22%-24% thermal efficiency.

Note: NCI analyzed a series of scenarios based on DOER and MTC assumptions that describe different hypothetical states of the world. The scenarios do not represent a NCI prediction or forecast, and they are not meant for predicting or bounding the most likely future.

Co-firing is economical with higher government incentives, and becoming economical over time without them.

Supported Development ***Accelerated Development***



Market-Based Development

Key Assumptions & Observations

- Economic analysis for co-firing compares LCOE of biomass co-firing with cost of producing power from coal (and not with grid market price).
- Lower case coal power assumed at \$0.045/kWh, flat through 2020 (based on interview with MA coal plant operator and EIA's Annual Energy Outlook (AEO) 2008 Reference forecast).
- Higher case coal power assumed at \$0.045/kWh, rising 1% per year, which is within the AEO 2008 high coal cost scenario.
- Co-firing biomass at coal facilities is economical at all times in the Accelerated Development and Supported Development scenarios, and becomes economical circa 2013 in Market-Based Development scenario.
- Commercial combined heat and power applications are not depicted here; they have the potential for better economics and smoother implementation.

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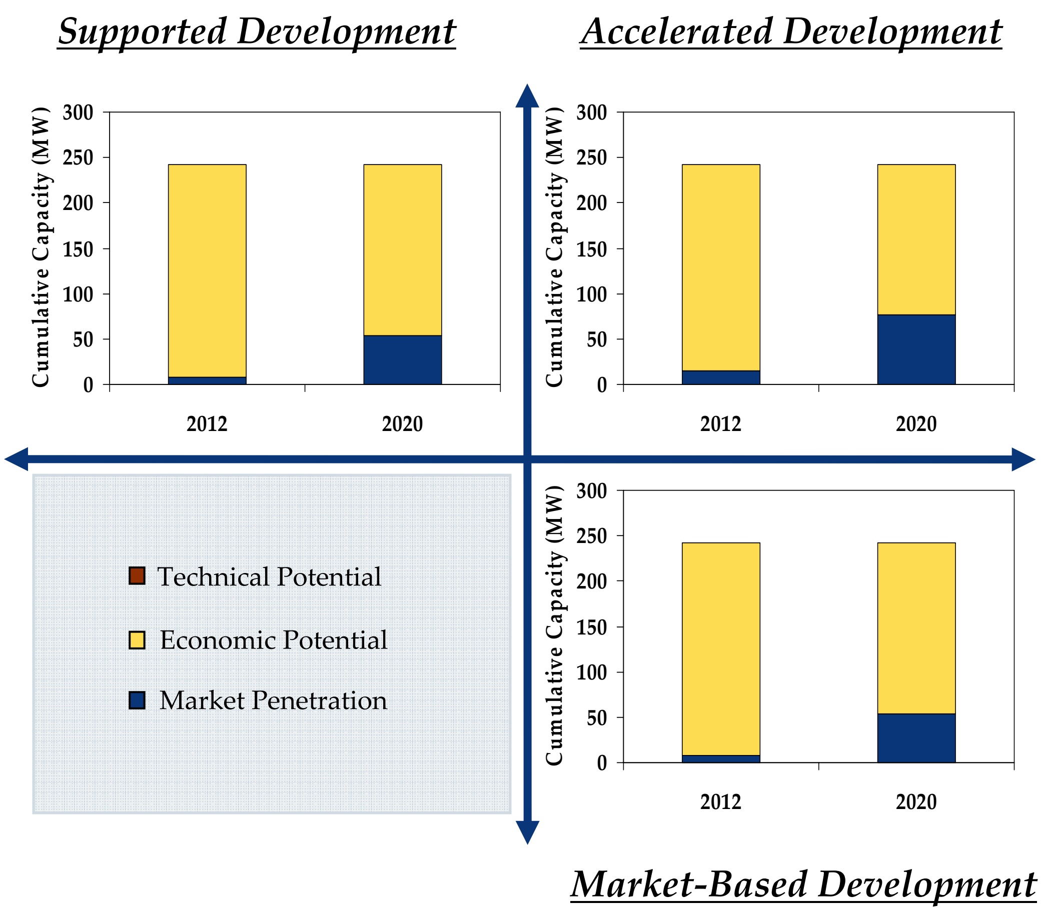
There are significant hurdles to implementation of larger-scale co-firing; possibly greater implementation potential with distributed CHP.



Note: NCI analyzed a series of scenarios based on DOER and MTC assumptions that describe different hypothetical states of the world. The scenarios do not represent a NCI prediction or forecast, and they are not meant for predicting or bounding the most likely future.

Key Assumptions & Observations

- ~ 1,690MW of coal power in MA; 10% co-firing results in 169MW technical potential (this is not in addition to technical potential discussed on previous slides).
- Significant hurdles to larger-scale co-firing:
  - To qualify for RECs, one needs to meet "advanced technology hurdle" and also lower emissions *from the entire coal plant.*
  - Biomass has a significantly lower energy density than coal and an increased material handling expense.
  - Coal plant operators are reluctant to make changes to existing operations in an uncertain regulatory environment.
- Potential exists for more rapid implementation of smaller, commercial CHP facilities. All market penetration is assumed to come from this type of facility.
- Projected CHP costs highly variable depending on numerous site-specific factors (from under $0.04 per kWh to over $0.12, per Crossman October 26, 2007 report).

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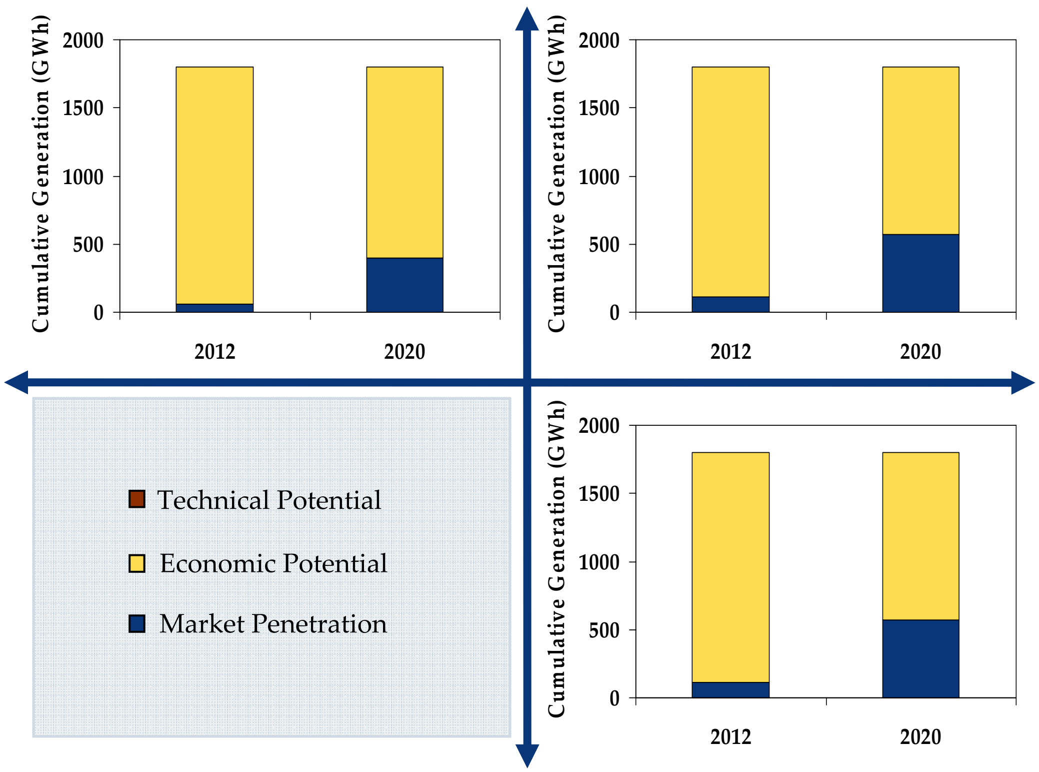
There are significant hurdles to implementation of larger-scale co-firing; possibly greater implementation potential with distributed CHP (cont.).

Supported Development *Accelerated Development*



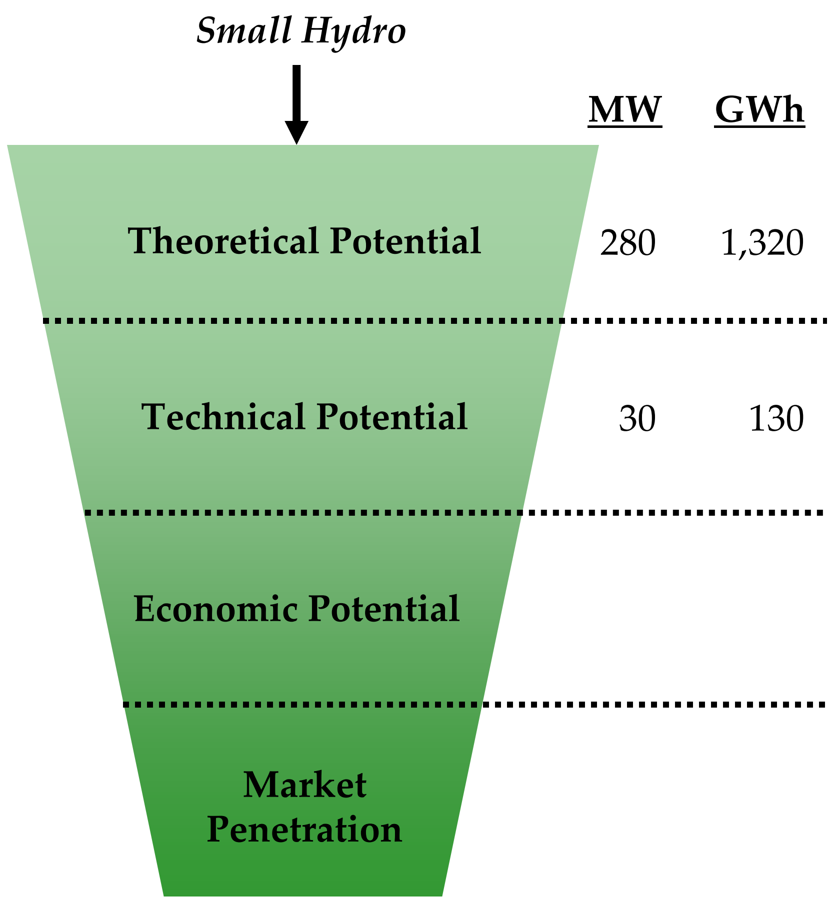
Market-Based Development

Key Assumptions & Observations

- CHP potential and implementation timeline based on NCI estimates, developed with reference to:
  - Data regarding nation-wide distribution of industrial facility sizes;
  - Estimates regarding MA industrial and commercial base; and
  - Discussions with DOER/MTC personnel.
- Over 500 GWh market penetration by 2020 in Accelerated Development and Market-Based Development scenarios.
- Analysis assumes 85% capacity factor.
- Additional technology assumptions set forth in Appendices.

Note: NCI analyzed a series of scenarios based on DOER and MTC assumptions that describe different hypothetical states of the world. The scenarios do not represent a NCI prediction or forecast, and they are not meant for predicting or bounding the most likely future.

There is 30 MW and 132 GWh of technical potential for small hydro power, based on the available resource and siting constraints.



Theoretical Potential

New Capacity:

- Idaho National Laboratory (INL) estimated the hydropower resource in MA.
- A 2006 INL study estimated the total hydropower resource at about 540 MW. 260 MW has already been developed, leaving about 280 MW of undeveloped feasible potential
- 1995 INL study estimated the undeveloped hydropower resource for 131 sites in MA at 325 MW with one set of assumptions and 132 MW with another.
- A 2003 INL estimates the average hydro capacity factor in MA at 48.4%.

Output Improvement:

- The Energy Policy Act of 2005 provides an incentive for output improvements >3%.
- Based on developer feedback a reasonable output improvement at a site could be 5%, some sites may be significantly high, ~20%.
- The theoretical potential assumes all existing sites could be retrofitted to increase output by 5%.

Technical Potential

New Capacity:

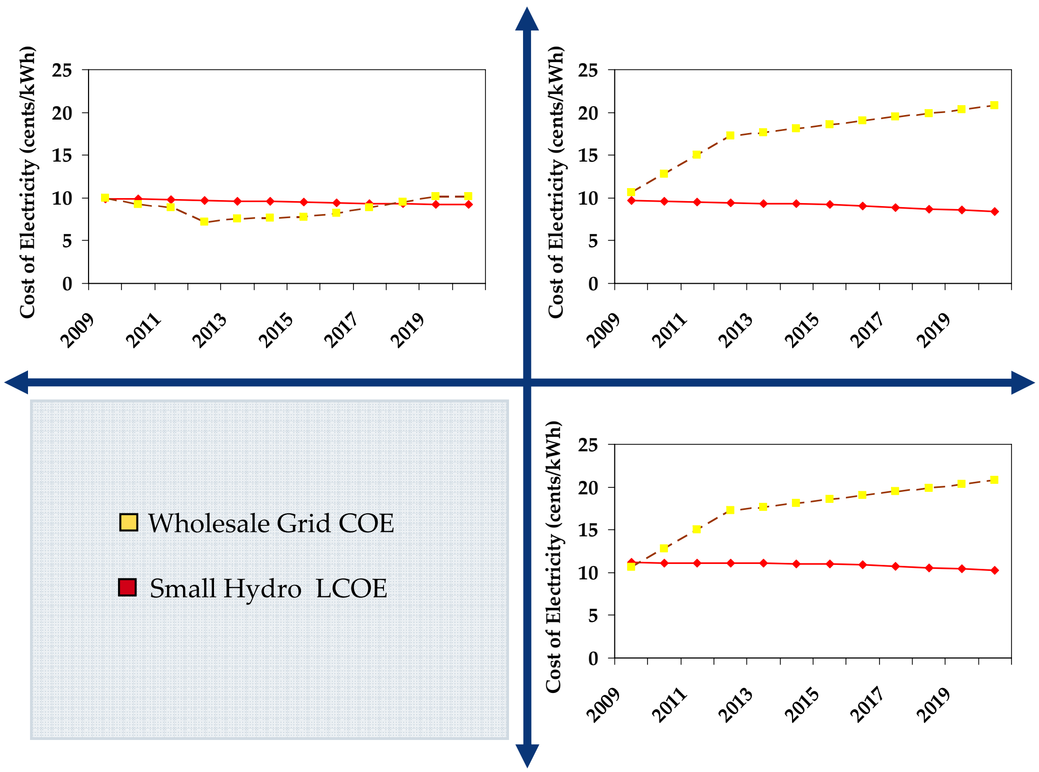
- The technical potential is based on Gomez and Sullivan's (G&S) assessment of the 131 sites identified in the 1995 INL study.
- G&S identified 45 sites with a total potential of 11.5 MW (undeveloped sites and dams without power).
- In addition to new sites, some existing sites (dams that once produced power) will be rehabilitated to produce power. G&S identified 19 sites with a total installed capacity of 14.7 MW with rehabilitation needs; about 5% of installed capacity.

Output Improvement:

- Additional sites beyond those identified with rehabilitation needs are likely to consider output improvements, another 5% of installed capacity.

The LCOE of small hydro will be less than wholesale electricity in the Accelerated Development and Market-Based Development scenarios.

Supported Development | *Accelerated Development*



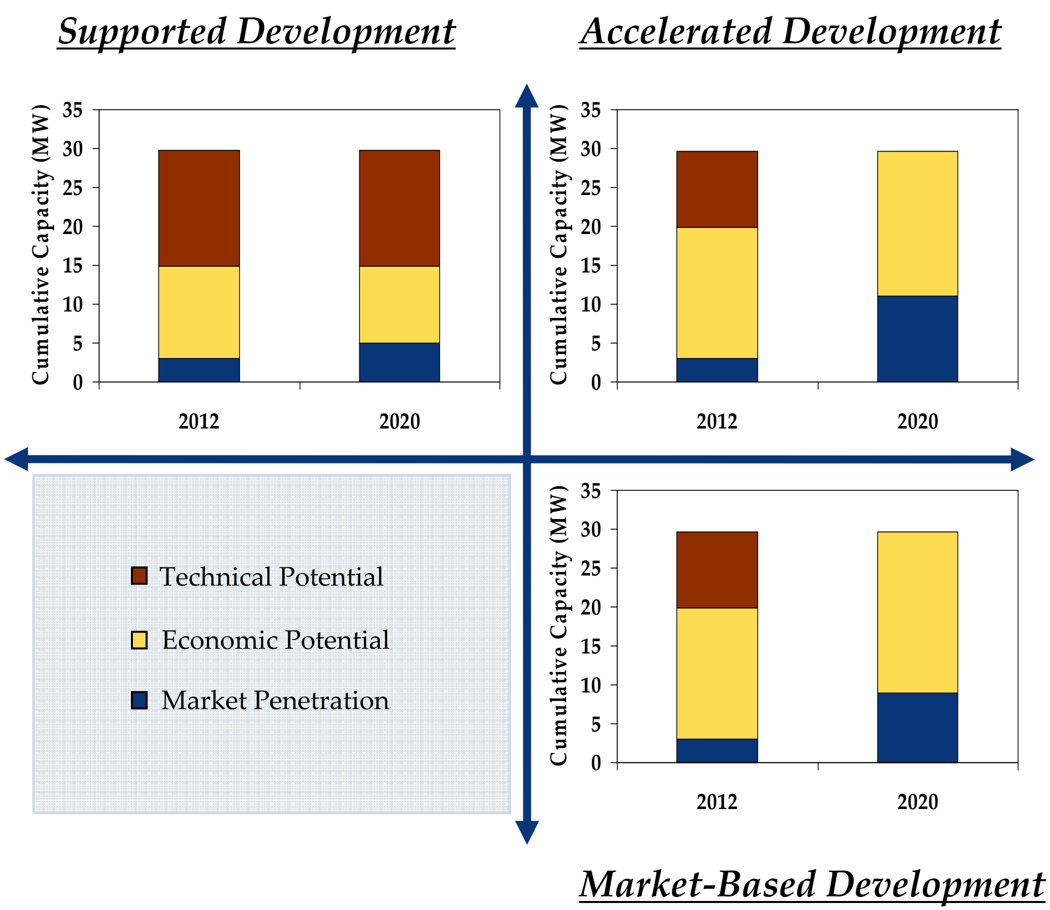
Market-Based Development

Key Assumptions & Observations

- Civil works account for a significant percentage of the plants' initial costs.
- Economics will be more favorable at sites with existing infrastructure.
- The LCOE presented to the left assumes a dam exists at the site.
- In addition, permitting will be easier at sites with existing infrastructure.
- In the Accelerated and Market-Based Development scenarios the economics are very favorable for small hydro development and improve over time.
- In the Supported Development scenario the economics are marginal throughout the period.

Note: The inputs for the LCOE analysis are provided in the Appendix.

Small hydro has a market penetration by 2012 of 3 MW and could increase to 5 to 11 MW by 2020.



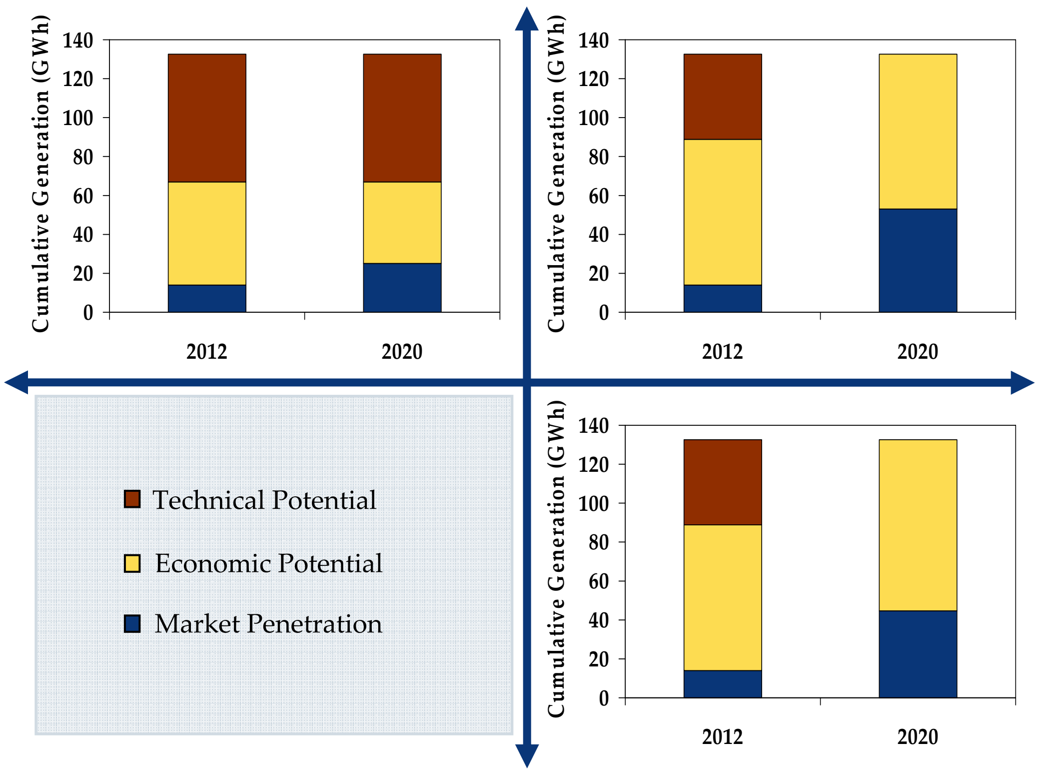
Key Assumptions & Observations

- New capacity additions will mainly be developed at sites with existing infrastructure (i.e., currently has a dam without power or a dam with power).
- The economics for small hydro additions become more favorable as grid prices increase.
- In all scenarios, the most economic and easiest to permit projects will proceed.
- Several small hydro projects are at various stages of development today; many of these projects would become operational by 2012 in all scenarios.

Note: NCI analyzed a series of scenarios based on DOER and MTC assumptions that describe different hypothetical states of the world. The scenarios do not represent a NCI prediction or forecast, and they are not meant for predicting or bounding the most likely future.

Small hydro has a market penetration by 2012 of 14 GWh and could increase to 25 to 53 GWh by 2020 (continued).

Supported Development *Accelerated Development*



Market-Based Development

Note: NCI analyzed a series of scenarios based on DOER and MTC assumptions that describe different hypothetical states of the world. The scenarios do not represent a NCI prediction or forecast, and they are not meant for predicting or bounding the most likely future.

Key Assumptions & Observations

New Capacity:

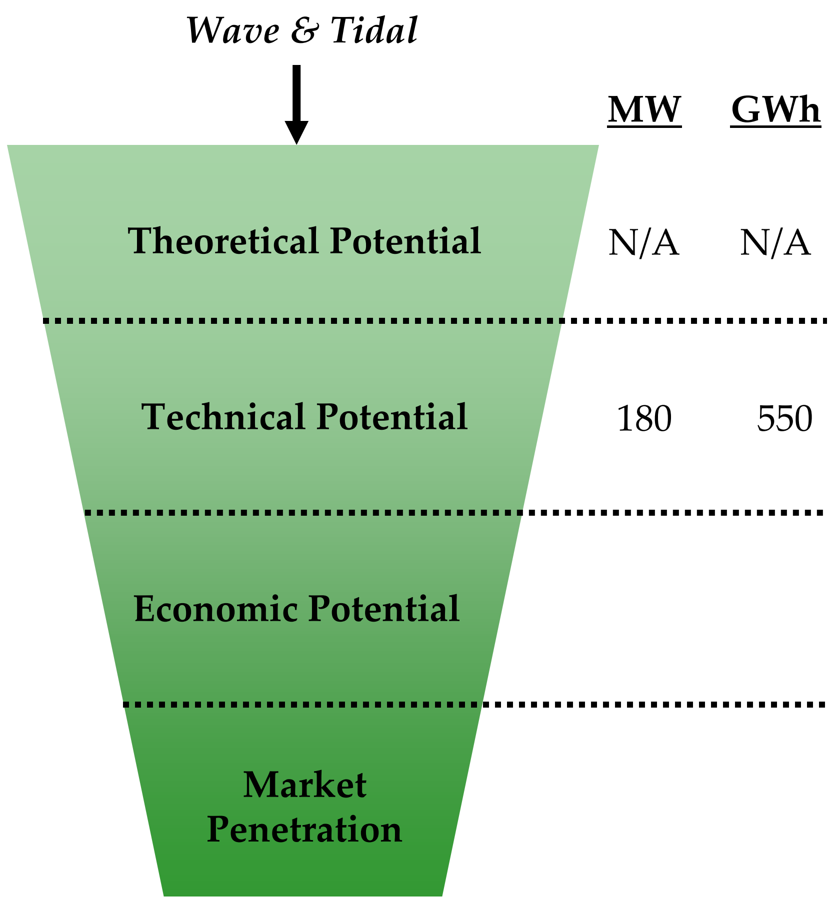
- Hydropower is dependent on precipitation. This leads to significant seasonal and annual variability of hydropower generation.
- The average hydro capacity factor in MA is 48.4%[1]
  - Peak is ~60% from March – May
  - Low is ~30% from July – September

Output Improvement:

- A retrofit increases output by 5%, without an increase in capacity

1. INL, *Estimation of Economic Parameters of U.S. Hydropower Resources*, June 2003

There is 180 MW of technical potential for wave and tidal energy, based on ocean resources and limited site availability.



Theoretical Potential

- A theoretical wave or tidal energy potential study has not been completed for Massachusetts.

Technical Potential

Wave:

- EPRI determined a 100 MW site off the coast of Truro could be developed for commercial purposes to generate 300 GWh/year
- Other potential sites were not identified

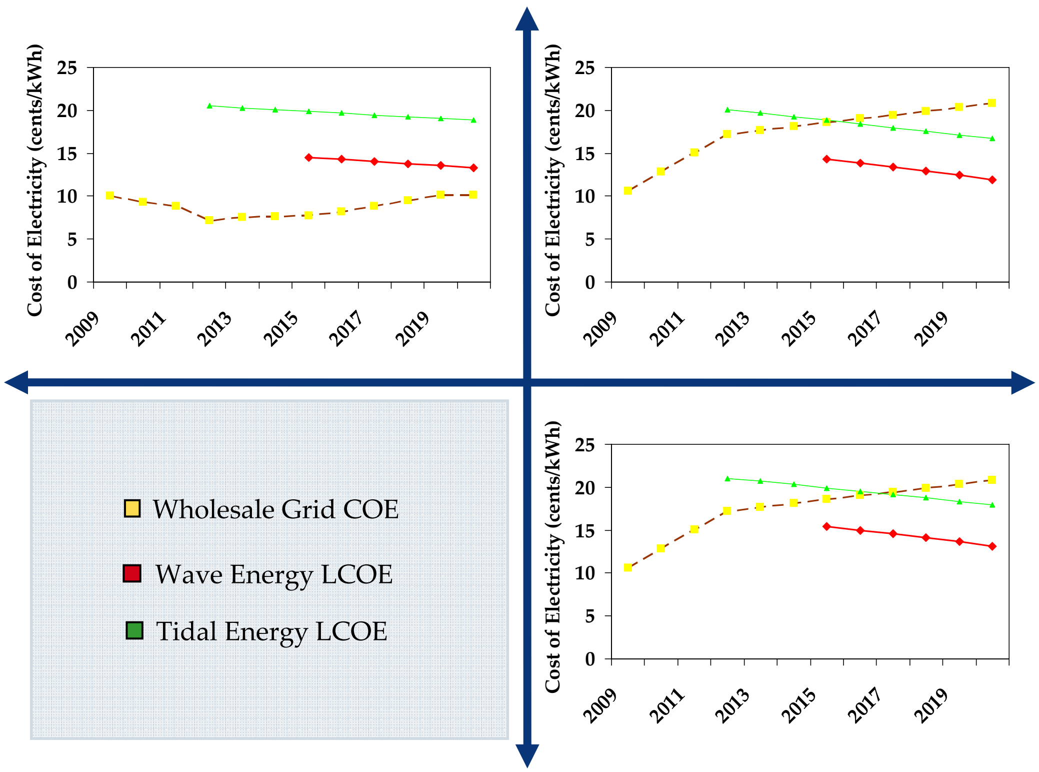
Tidal:

- EPRI analyzed the tidal energy resource off the Massachusetts coast and identified six sites with tidal currents >1.5 m/s.
- Three of these sites are undergoing development.
- The technical potential assumes these three sites are developed to their maximum size, about 80 MW.

Wave and tidal energy LCOE will reach grid parity in the 2015-2018 timeframe in the Accelerated and Market-Based Development scenarios.

Supported Development

Accelerated Development



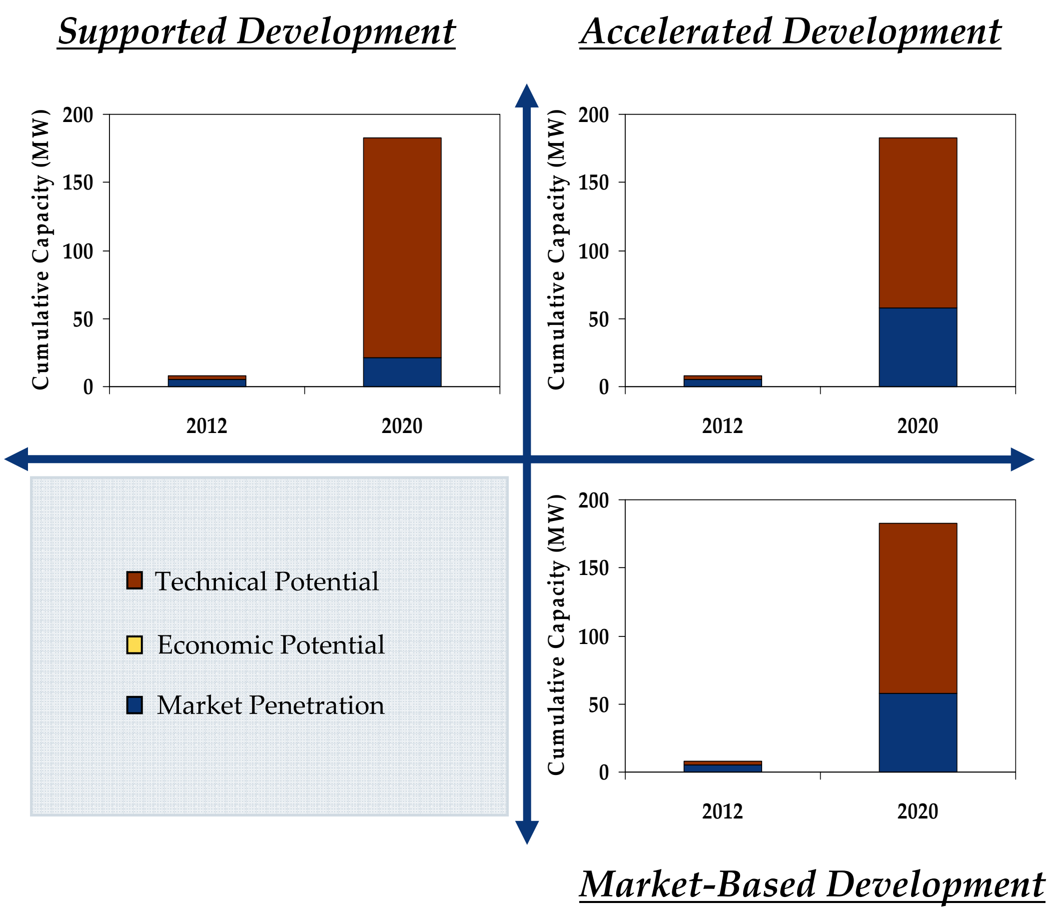
Market-Based Development

Note: The inputs for the LCOE analysis are provided in the Appendix.

Key Assumptions & Observations

- Wave energy technology is currently in the pilot stage. Projects today are designed to test the technology, not necessarily be cost effective.
- Tidal energy was at a similar stage a couple of years ago. The technology is moving from pilots to demonstrations, where project economics are becoming more important.
- The technical success and project economics will determine whether or not tidal energy projects will proceed to commercial-scale (>5 MW).
- Project economics will also dictate the size of the commercial-scale project; developers will likely develop larger areas within each site with improved economics.

Ocean energy could have a market penetration by 2012 of 5 MW and could increase to 22 to 58 MW by 2020.



Note: NCI analyzed a series of scenarios based on DOER and MTC assumptions that describe different hypothetical states of the world. The scenarios do not represent a NCI prediction or forecast, and they are not meant for predicting or bounding the most likely future.

Key Assumptions & Observations

Tidal:

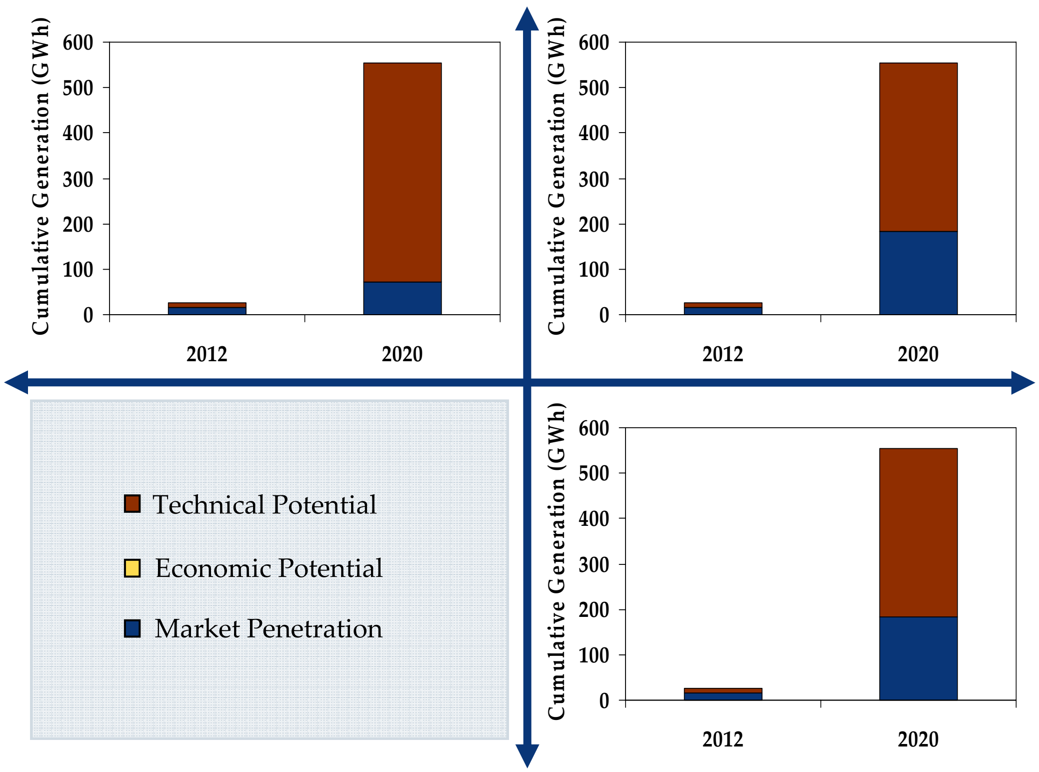
- 6 sites in MA meet EPRI's tidal energy selection criteria; 3 sites undergoing development.
- At the 3 sites in all scenarios by 2012 pilot-scale activities (< 5 MW) are underway.
- Technology advances enable commercial-scale tidal energy projects after 2012.
- In all scenarios commercial-scale activities proceed at each site.
- Estimates of the size of commercial-scale projects based on developer interviews and relative project economics.
- ~80 MW technical potential assumes the 3 sites are developed to their maximum size.

Wave:

- 1 site in MA identified as a candidate wave energy site by EPRI. No developers actively pursuing the site.
- Technology advances enable commercial-scale wave energy projects after 2012, but none are developed in MA.
- ~100 MW technical potential.

Ocean energy could have a market penetration by 2012 of 17 GWh and could increase to 71 to 180 GWh by 2020 (continued).

Supported Development | ***Accelerated Development***



Market-Based Development

Key Assumptions & Observations

Tidal:

- 6 sites in MA meet EPRI's tidal energy selection criteria; 3 sites undergoing development.
- Capacity factors range from 35 to 40%.
- In all scenarios commercial-scale activities proceed at each site.
- Estimates of the size of commercial-scale projects based on developer interviews and relative project economics.

Wave:

- 1 site in MA identified as a candidate wave energy site by EPRI. No developers actively pursuing the site.
- Capacity factor estimated at 34% for the site identified by EPRI.

Note: NCI analyzed a series of scenarios based on DOER and MTC assumptions that describe different hypothetical states of the world. The scenarios do not represent a NCI prediction or forecast, and they are not meant for predicting or bounding the most likely future.

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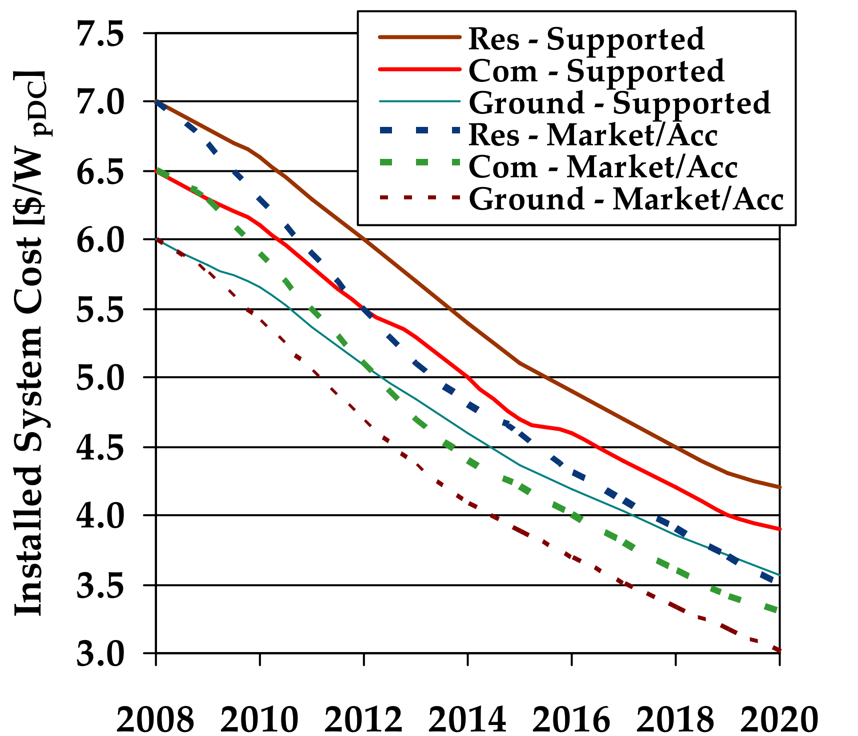
NCI analyzed two PV system pricing scenarios.

PV System Pricing



PV Economic and Technical Assumptions (2008$)	Residential Rooftop	Commercial Rooftop	Ground Mounted
Plant Capacity (kW_{pDC})	4	100	500
2008 Installed Cost ($/$kW_{pDC}$)	7,000	6,500	6,000
Project Life (yrs)	25	25	25
2008 Fixed O&M ($/kW-yr)[2]	51	46.4	46.4
Average Annual O&M Cost Decline (%)	-3.9%	-5.1%	-5.1%
System Tilt (°)	30	5	30
Net Capacity Factor[3]	13.5%	10.7%	13.5%

Notes and Sources:

- Source: NCI July 2008. Supported Development scenario assumes installed system costs decline at historical rates. The Market-Based Development and Accelerated Development scenarios assumes accelerated price declines.
- Inverter replacement costs are included in the installed system costs.
- The prices shown do not include federal incentives. The Supported Development and Accelerated Development scenarios assume current federal incentives for PV ($2,000/system residential and 30% of system cost for non-residential) are extended through 2020. The Market-Based Development scenario assumes credits expire at the end of 2008.

NCI analyzed MA' rooftop PV market using floor space data, data on building characteristics and PV efficiency.

Rooftop

Floor Space Data (Sq. Ft.)	Building Characteristics (Floors/Building)	PV System Efficiency (W/Sq. Ft)	Theoretical Potential (MW)
NCI used residential and commercial installed and projected floor space data from McGraw-Hill.	NCI used EIA building characteristic data	NCI used 2008 system power density of 10 MW/million sq. ft., increasing to 13.7 by 2020	• Residential: – **2008 – 15.8 GW** – **2020 – 24.1 GW** • Commercial: – **2008 – 4.8 GW** – **2020 – 7.2 GW**

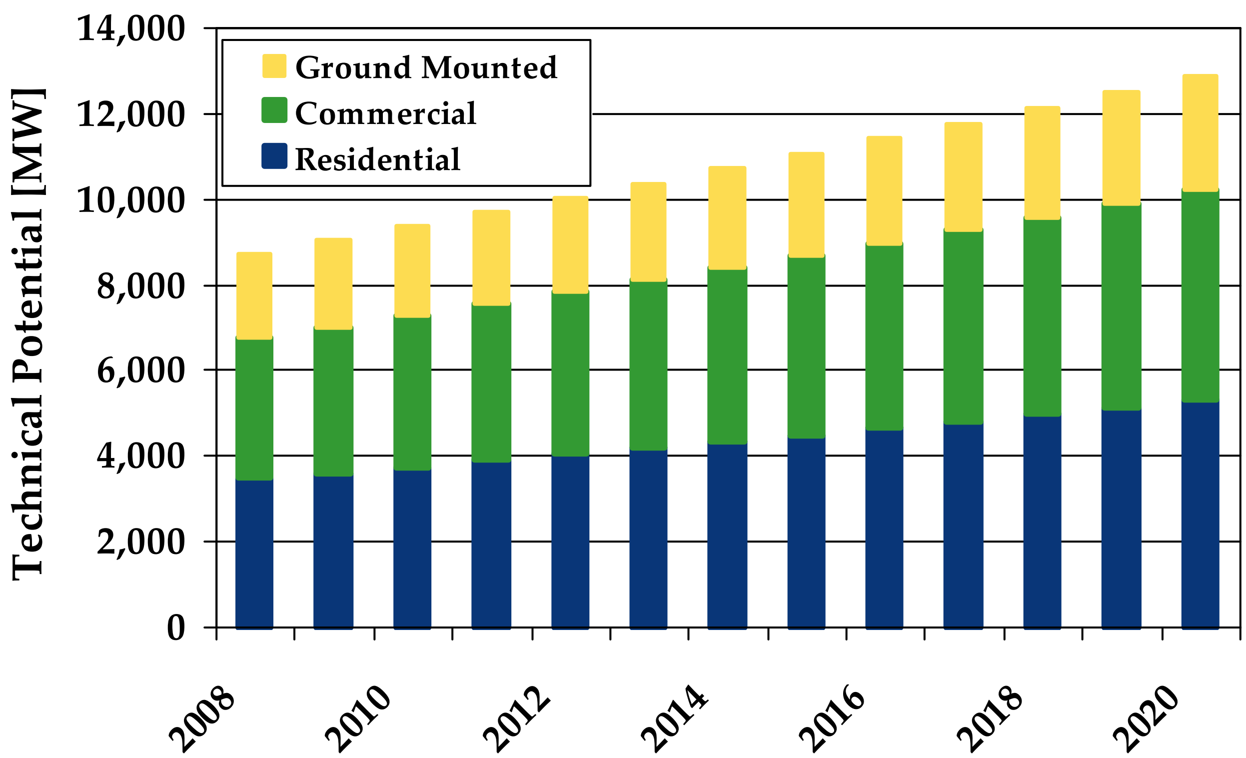
Ground Mounted

Available Land (Sq. Ft.)	PV System Efficiency (W/Sq. Ft)	Theoretical Potential (MW)
NCI used the Mass. GIS database and tabulated sum of abandoned agricultural land and areas of no vegetation.	NCI assumed a 30º system tilt and arrived at 6.0 MW/million sq. ft, increasing to 8.2 by 2020.*	• Ground Mounted: – **2008 – 7.9 GW** – **2020 – 10.6 GW**

* The system efficiency for ground mounted systems is lower than for rooftop systems because the ground mounted systems must be spread out over an area to alleviate shading caused by the system tilt.

Increasing roof space and improved PV system efficiency lead to increasing technical potential with time.

Technical Potential*



* Going from theoretical to technical potential involves screening out roof space for things like shading, orientation, and HVAC equipment. NCI used a 22% PV Access Factor for residential rooftops and 65% for commercial rooftop. NCI assumed simple assumption that 25% of the ground mounted theoretical potential could actually be developed for PV. This accounts for factors like soil stability, orientation, proximity to transmission, etc.

NCI accounted for utility owned PV systems and calculated the investment level that will be rate-based.

Utility Owned PV Systems

- MA's Green Communities Act allows for utility ownership of PV systems
  - The bill allows up to 50 MW of PV, per IOU in 2010.
- NCI assumed the technical potential for utility owned PV is 150 MW and that actual utility adoption levels will be driven by public utility commission decisions, public policy, politics, and public relations efforts.
- To look at the rate base impact of this program, we assumed 10 MW are installed by each utility by 2010.
  - The Supported Development scenario results in **$169 million** of investment being rate based across the three IOUs to achieve 30 MW by 2010.
  - The Market-Based Development and Accelerated Development scenarios result in **$162 million** of investment being rate based across the three IOUs to achieve 30 MW by 2010.

Note: NCI analyzed a series of scenarios based on DOER and MTC assumptions that describe different hypothetical states of the world. The scenarios do not represent a NCI prediction or forecast, and they are not meant for predicting or bounding the most likely future.

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The MTC requested a "bottom-up" analysis to calculate the level of state funding required to meet the 250 MW goal.[1,2]

Impact of Commonwealth Solar Rebate Program					
Scenario	**Residential Rebate [$/W]**	**Commercial Rebate [$/W]**	**Ground Mounted Rebate [$/W]**	**State Funding Spent Through 2011 [$M]**	**MW Installed 2008-2011 [MW]**
Market-Based Development	3.10	3.06	1.91	68	25
Supported Development	3.10	3.06	1.91	33	11
Accelerated Development	3.10	3.06	1.91	68	25

PV Analysis to Achieve 250 MW by 2017				
Scenario	**Residential Rebate[3] [$/W]**	**Commercial Rebate[3] [$/W]**	**Ground Mounted Rebate[3] [$/W]**	**Funding Required: 2012 – 2017[4] [$M]**
Market-Based Development	0	0	0	162
Supported Development	2.31	2.31	1.42	643
Accelerated Development	0	0	0	162

Notes:

- NCI analyzed a series of scenarios based on DOER and MTC assumptions that describe different hypothetical states of the world. The scenarios do not represent a NCI prediction or forecast, and they are not meant for predicting or bounding the most likely future.
- For each of the three scenarios, NCI kept current funding levels constant through 2011, and then calculated what incentive level is required to reach 250 MW by 2017. To simplify the analysis, NCI assumed unlimited state funding from 2008 to 2017. NCI also assumed a ratio between residential and commercial incentives consistent with current rebates (~1:1) and a ratio between residential and a 500 kW ground mount system (3:2)
- This is the rebate required to achieve 250 MW by 2017, assuming 30 MW are installed in utility owned systems.
- This includes the rebate program and utility investment that must be rate based.

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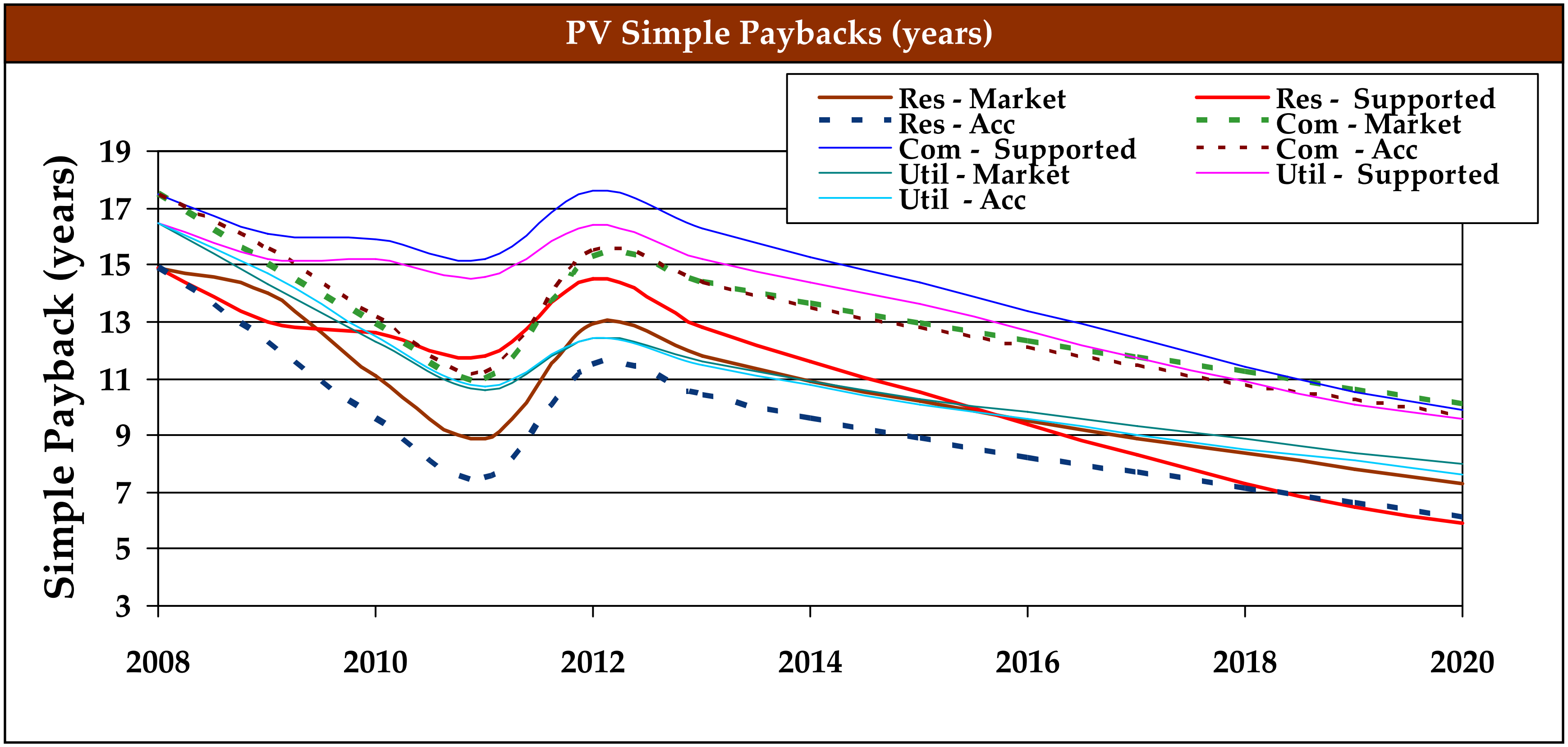
Simple paybacks for the three PV system types show improving paybacks over time for all three scenarios.



Notes:

1. NCI analyzed a series of scenarios based on DOER and MTC assumptions that describe different hypothetical states of the world. The scenarios do not represent a NCI prediction or forecast, and they are not meant for predicting or bounding the most likely future.
2. Declines are driven by rising market electricity prices and declining system costs.
3. The spike in 2012 occurs because this is the year that current state funding for the rebate ends.

The ITC, PTC and Accelerated Depreciation have a significant impact on the LCOE of renewable energy investments.

Incentive	Description	Applicability				
		Wind	Solar	Biomass	Hydro	Ocean
Production Tax Credit (PTC)	• 2.0 ¢/kWh, after tax, for first 10 years of operation. PTC is indexed to inflation and applies to projects installed through 12/31/2008. • Credit value is 1.0 ¢/kWh for "open-loop" biomass, small irrigation power/qualified hydro production, cogeneration and waste-to-energy	Y	Pre-01/2006	Y	Y	N
Renewable Energy Production Incentive (REPI)[1]	• Rough equivalent to the PTC but for public power entities. • 1.50¢/kWh (1993 $) adjusted for inflation for the first 10 years of operation. The REPI is subject to annual appropriations such that it may not be fully funded from year to year. • EPAct 2005 reauthorized this program through 2026 (i.e., for projects installed through 2016)	Y	Y	Y	Y	Y
Corporate Investment Tax Credit (ITC)	• Credit against income tax as percent of investment. After 12/31/2008 30% credit will revert back to 10%	N	30%	N	N	N
Accelerated Depreciation	• Eligible technologies are classified under Modified Accelerated Cost Recovery System (MACRS) property class 5, allowing 5 year vs. 15 year depreciation	Y	Y	Y	N	N

Notes:
1. The REPI is subject to annual appropriations such that it may not be fully funded from year to year.

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A number of incentives and other areas of support exist for wind energy in MA.

MTC Support Programs for RE Projects					
	Wind	Solar	Biomass	Hydro	Ocean
Clean Energy Pre-Development Financing Initiative - Provides grants and loans supporting pre-development for grid-tied RE generating facilities in New England. Project must provide 50% of electricity to wholesale market. Minimum project is 3 MW for wind and biomass, 250 kW for hydro, and 1 MW for other projects. Public entities can apply for feasibility study grants with a $50k cap. All eligible entities can apply for pre-development loans: $250k cap for wind and biomass, $150k cap for other technologies.	Y	N	Y	Y	N
Commonwealth Solar Rebates* - Provides rebates through a non-competitive application process for the installation of PV projects at residential, commercial, industrial, and public facilities. Non-residential projects are eligible for rebates for PV projects up to 500 kW and residential projects are eligible for up to 5 kW. The applicant (and project site) must be a customer of a MA investor-owned electric utility. $2.00/$W_{pDC}$ base for residential; $3.25/$W_{pDC}$ for the first 25 kW_{pDC} of system capacity, $3.00/$W_{pDC}$ for the next 75 kW, $2.00/$W_{pDC}$ for the next 100 kW, $1.50/$W_{pDC}$ for the next 300 kW_{pDC} for commercial.	N	Y	N	N	N

Source: http://www.masstech.org/renewableenergy/index.html. Reviewed July 2008.

* The programs with an asterisk were included in the modeling of the levelized cost of energy (LCOE) for the renewable technologies because they have an appreciable impact on the cost. Their values were held constant across the scenarios.

A number of incentives and other areas of support exist for wind energy in MA (continued).

MTC Support Programs for RE Projects (continued)					
	Wind	Solar	Biomass	Hydro	Ocean
Community Wind Collaborative* - MTC offers feasibility studies at no charge to MA municipalities that meet certain criteria. The Standard Financial Offer (SFO) assists municipalities committed to a wind project on municipally-owned or controlled land through late-stage development hurdles. Through the SFO, MTC offers municipalities (1) access to $150k or equivalent in services needed for development, and (2) project financing through a RECs purchase agreement ($40/MWh or $1.2 million/MW up to 3 MW + $400k/MW for up to 2 additional MW).	Y	N	N	N	N
Green Schools Initiative - Provides design support grants of up to $100k and RE installation grants up to $300k (not to exceed $10/watt (dc) for PV and $8/watt (peak) for wind) for projects in eligible schools.	Y	Y	N	N	N
Large Onsite Renewables Initiative (LORI) Grants* - Awards grants for feasibility studies and design and construction for RE projects over 10 kW. A project must be (1) located at a commercial, industrial, institutional, or public site and (2) slated for service by a MA investor-owned electric utility. Feasibility grants are capped at $40k. Design grants capped at the lesser of $125k or 75% of actual cost, and construction grants capped at the lesser of $275k or 75% of actual costs.	Y	N	Y	Y	N

Source: http://www.masstech.org/renewableenergy/index.html. Reviewed July 2008.

* The programs with an asterisk were included in the modeling of the levelized cost of energy (LCOE) for the renewable technologies because they have an appreciable impact on the cost. Their values were held constant across the scenarios.

A number of incentives and other areas of support exist for renewable energy in MA (continued).

MTC Support Programs for RE Projects (continued)					
	Wind	Solar	Biomass	Hydro	Ocean
Small Hydropower Initiative: Wholesale Generation Solicitation* - Provides construction grants and loans, as well as pre-paid contracts for RECs associated with incremental hydropower, for projects that upgrade, rehabilitate, develop, or redevelop eligible facilities with nameplate capacity between 100 kW and 30 MW. Grants and pre-paid REC contracts are limited to $750k per project; loans are limited to $1 million per project.	N	N	N	Y	N
Small Renewables Initiative (SRI) Rebates - Provides rebates for the installation of projects up to 10 kW at residential, commercial, industrial, institutional, and public facilities. SRI slated to distribute ~$3.6 million/yr in rebates from 2005 to 2010, but program is changing. Solar is no longer supported and wind funding was suspended in 6/2008 as MTC re-evaluates the program. Only 2 hydro projects funded to date. Wind: $2.25/$W_{AC}$ & Micro-hydroelectric: $4.00/$W_{AC}$.	Y	N	N	Y	N

Source: http://www.masstech.org/renewableenergy/index.html. Reviewed July 2008.

* The programs with an asterisk were included in the modeling of the levelized cost of energy (LCOE) for the renewable technologies because they have an appreciable impact on the cost. Their values were held constant across the scenarios.

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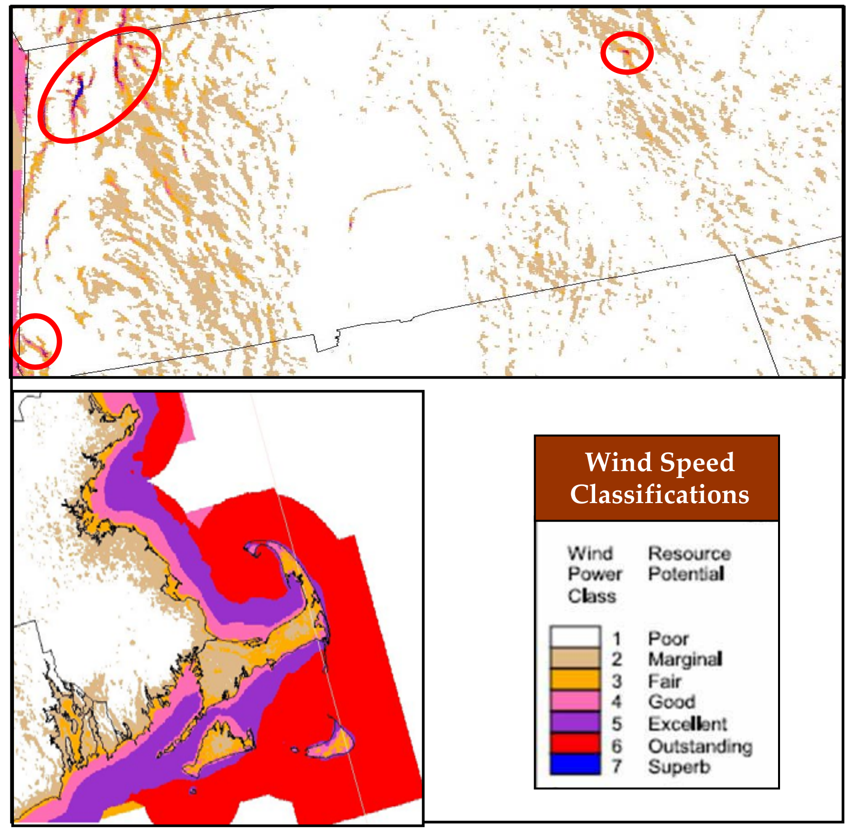
Fair to good (Class 3 and 4 winds[1]) onshore wind is found along the coast and in ridgeline pockets of the west.

- Almost all the Class 3[1] or better wind resources can be found along the coastline (see lower map to right).
  - Most of this potential is in land designated as wetlands, followed by "barren land" (mostly beaches)
  - Virtually the entire coastline, with the exception of areas that are particularly sheltered, could be considered potential for small, community-based turbine clusters.
- There are a couple of distinct ridgelines (see red circles in upper map to the right) in the western portion of the state which are the only significant non-shoreline wind resources. Much of this land is labeled as forest according to land use classifications.
- The University of Massachusetts at Amherst's Renewable Energy has done a comprehensive review of potential utility-scale sites based on wind regimes and land use characteristics. Based on interviews, no one has completed such an analysis for community-scale wind sites.



1. Higher wind class is better, with Class 3 typically considered the minimum required for wind power development. At 50 meter wind speeds: Class 5 = 7.5-8.0 m/s (16.8-17.9 mph); Class 4 = 7.0-7.5m/s (15.7-16.8 mph); Class 3 = 6.4-7m/s (14.3-15.7 mph).

A rise in installed costs has hurt wind economics. A stabilization is expected in the near term followed by a gradual decline.

	Onshore 600 kW Community Wind Power Economic and Performance Assumptions for Given Year of Installation (2008$)		
	2008 market/supported/acc	**2012** market/supported/acc	**2020** market/supported/acc
Plant Capacity (MW)[1]	0.6 / 0.6 / 0.6	0.6 / 0.6 / 0.6	0.6 / 0.6 / 0.6
Project Life (yrs)	25 / 25 / 25	25 / 25 / 25	25 / 25 / 25
Total Installed Cost ($/kW)[2]	$2,900 / $2,900 / $2,900	$2,732 / $2,844 / $2,732	$2,320 / $2,620 / $2,320
Fixed O&M ($/kW-yr)[2]	$30 / $30 / $30	$22 / $26 / $22	$20 / $25 / $20
Non-fuel variable O&M ($/MWh)[2]	$0 / $0 / $0	$0 / $0 / $0	$0 / $0 / $0
Net Capacity Factor (%)[3]	21% / 21% / 21%	21% / 21% / 21%	21% / 21% / 21%

Sources: NCI Estimates 2008. *Renewable Energy Costs of Generation Inputs for IEPR 2007*, April 2007, prepared for CEC/PIER. *Renewable Energy: Costs, Performance and Markets – an outlook to 2015.* NCI report for CEA Technologies, June 22, 2007, NREL: *Annual Report on U.S. Wind Power Installation, Cost, and Performance Trends: 2007,* May 2008, Interviews with MA community wind developers and regulators, June 2008.

1. For the economic analysis, a single 600 kW turbine community-scale project was used to represent projects with less than 5 turbines with individual turbines ranging from 500 kW to 1 MW.
2. NCI cost estimates are based on reports for CEA Technologies, CEC/PIER, NREL, and interviews. Under the high renewable energy cost setting, costs flatten to 2010, followed by a decline of 1%/yr after 2010 based on increased domestic turbine manufacturing and stabilizing commodity prices. Under the low renewable cost setting, a decline of 1%/yr is assumed for the first two years followed by a 2%/yr decline post-2010. Fixed O&M cost assumptions and declines are based on CEC/PIER.
3. The capacity factor represents an average capacity factor across wind classes. The cross-wind class factor was used because of data limitations in terms of data distinguishing wind regimes for current and future community wind projects. The value is based on NREL values for New England projects and interviews. The capacity factor is the same as for the 1.5 MW community wind project because capacity factors vary more based on wind speed than turbine size.

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Larger turbines have a lower installed cost, which improves project economics.

	Onshore 1.5 MW Community Wind Power Economic and Performance Assumptions for Given Year of Installation (2008$)		
	2008 market/supported/acc	**2012 market/supported/acc**	**2020 market/supported/acc**
Plant Capacity (MW)[1]	1.5 / 1.5 / 1.5	1.5 / 1.5 / 1.5	1.5 / 1.5 / 1.5
Project Life (yrs)	25 / 25 / 25	25 / 25 / 25	25 / 25 / 25
Total Installed Cost ($/kW)[2]	$2,600 / $2,600 / $2,600	$2,454 / $2,548 / $2,454	$2,090 / $2,350 / $2,090
Fixed O&M ($/kW-yr)[2]	$30 / $30 / $30	$22 / $26 / $22	$20 / $25 / $20
Non-fuel variable O&M ($/MWh)[2]	$0 / $0 / $0	$0 / $0 / $0	$0 / $0 / $0
Net Capacity Factor (%)[3]	21% / 21% / 21%	21% / 21% / 21%	21% / 21% / 21%

Sources: NCI Estimates 2008. *Renewable Energy Costs of Generation Inputs for IEPR 2007*, April 2007, prepared for CEC/PIER. *Renewable Energy: Costs, Performance and Markets – an outlook to 2015.* NCI report for CEA Technologies, June 22, 2007, NREL: *Annual Report on U.S. Wind Power Installation, Cost, and Performance Trends: 2007,* May 2008, Interviews with MA community wind developers and regulators, June 2008.

1. For the economic analysis, a single 1.5 MW turbine community-scale project was used to represent projects with less than 5 turbines with individual turbines greater in rated capacity than 1 MW.
2. NCI cost estimates are based on reports for CEA Technologies, CEC/PIER, NREL, and interviews. Under the high renewable energy cost setting, costs flatten to 2010, followed by a decline of 1%/yr after 2010 based on increased domestic turbine manufacturing and stabilizing commodity prices. Under the low renewable cost setting, a decline of 1%/yr is assumed for the first two years followed by a 2%/yr decline post-2010. Fixed O&M cost assumptions and declines are based on CEC/PIER.
3. The capacity factor represents an average capacity factor across wind classes. The cross-wind class factor was used because of data limitations in terms of data distinguishing wind regimes for current and future community wind projects. The value is based on NREL values for New England projects and interviews. The capacity factor is the same as for the 600 kW community wind project because capacity factors vary more based on wind speed than turbine size.

A recent rise in installed costs has hurt wind economics. A stabilization is expected in the near term followed by a gradual decline.

	Onshore 7.5 MW Class 2 Utility Wind Power Economic and Performance Assumptions for Given Year of Installation (2008$)		
	2008 market/supported/acc	**2012** market/supported/acc	**2020** market/supported/acc
Plant Capacity (MW)[1]	7.5 / 7.5 / 7.5	7.5 / 7.5 / 7.5	7.5 / 7.5 / 7.5
Project Life (yrs)	25 / 25 / 25	25 / 25 / 25	25 / 25 / 25
Total Installed Cost ($/kW)[2]	$2,500 / $2,500 / $2,500	$2,354 / $2,452 / $2,354	$2,000 / $2,260 / $2,000
Fixed O&M ($/kW-yr)[2]	$30 / $30 / $30	$22 / $26 / $22	$20 / $25 / $20
Non-fuel variable O&M ($/MWh)[2]	$0 / $0 / $0	$0 / $0 / $0	$0 / $0 / $0
Net Capacity Factor (%)[3]	22% / 22% / 22%	22% / 22% / 22%	22% / 22% / 22%

Sources: NCI Estimates 2008. *Renewable Energy Costs of Generation Inputs for IEPR 2007*, April 2007, prepared for CEC/PIER. *Renewable Energy: Costs, Performance and Markets – an outlook to 2015.* NCI report for CEA Technologies, June 22, 2007, NREL: *Annual Report on U.S. Wind Power Installation, Cost, and Performance Trends: 2007*, May 2008, Interviews with MA community wind developers and regulators, June 2008.

1. For the economic analysis, a representative project size of 7.5 MW was assumed based on a five 1.5 MW turbine wind project.
2. NCI cost estimates are based on reports for CEA Technologies, CEC/PIER, NREL, and interviews. Under the high renewable energy cost setting, costs flatten to 2010, followed by a decline of 1%/yr after 2010 based on increased domestic turbine manufacturing and stabilizing commodity prices. Under the low renewable cost setting, a decline of 1%/yr is assumed for the first two years followed by a 2%/yr decline post-2010. Fixed O&M cost assumptions and declines are based on CEC/PIER.
3. The capacity factor is based on information from NREL's report, NCI's reports for CEA Technologies and CEC/PIER, and an interview with a local wind developer. The upper end of capacity factors for Class 2 sites was used based on the assumption that utility-scale projects would pick sites with the best available wind.

A rise in installed costs has hurt wind economics. A stabilization is expected in the near term followed by a gradual decline.

	Onshore 7.5 MW Class 3 Utility Wind Power Economic and Performance Assumptions for Given Year of Installation (2008$)		
	2008 market/supported/acc	**2012** market/supported/acc	**2020** market/supported/acc
Plant Capacity (MW)[1]	7.5 / 7.5 / 7.5	7.5 / 7.5 / 7.5	7.5 / 7.5 / 7.5
Project Life (yrs)	25 / 25 / 25	25 / 25 / 25	25 / 25 / 25
Total Installed Cost ($/kW)[2]	$2,500 / $2,500 / $2,500	$2,354 / $2,452 / $2,354	$2,000 / $2,260 / $2,000
Fixed O&M ($/kW-yr)[2]	$30 / $30 / $30	$22 / $26 / $22	$20 / $25 / $20
Non-fuel variable O&M ($/MWh)[2]	$0 / $0 / $0	$0 / $0 / $0	$0 / $0 / $0
Net Capacity Factor (%)[3]	27% / 27% / 27%	27% / 27% / 27%	27% / 27% / 27%

Sources: NCI Estimates 2008. *Renewable Energy Costs of Generation Inputs for IEPR 2007*, April 2007, prepared for CEC/PIER. *Renewable Energy: Costs, Performance and Markets – an outlook to 2015.* NCI report for CEA Technologies, June 22, 2007, NREL: *Annual Report on U.S. Wind Power Installation, Cost, and Performance Trends: 2007*, May 2008, Interviews with MA community wind developers and regulators, June 2008.

1. For the economic analysis, a representative project size of 7.5 MW was assumed based on a five 1.5 MW turbine wind project.
2. NCI cost estimates are based on reports for CEA Technologies, CEC/PIER, NREL, and interviews. Under the high renewable energy cost setting, costs flatten to 2010, followed by a decline of 1%/yr after 2010 based on increased domestic turbine manufacturing and stabilizing commodity prices. Under the low renewable cost setting, a decline of 1%/yr is assumed for the first two years followed by a 2%/yr decline post-2010. Fixed O&M cost assumptions and declines are based on CEC/PIER.
3. The capacity factor is based on information from NREL, NCI's reports for CEA Technologies and CEC/PIER, and interviews.

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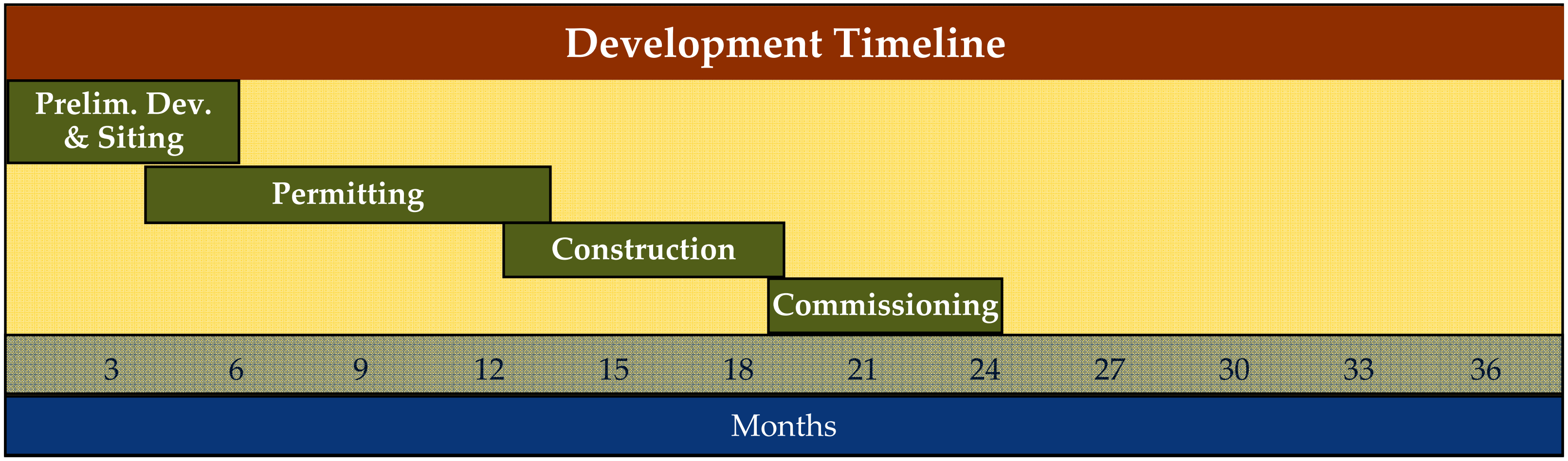
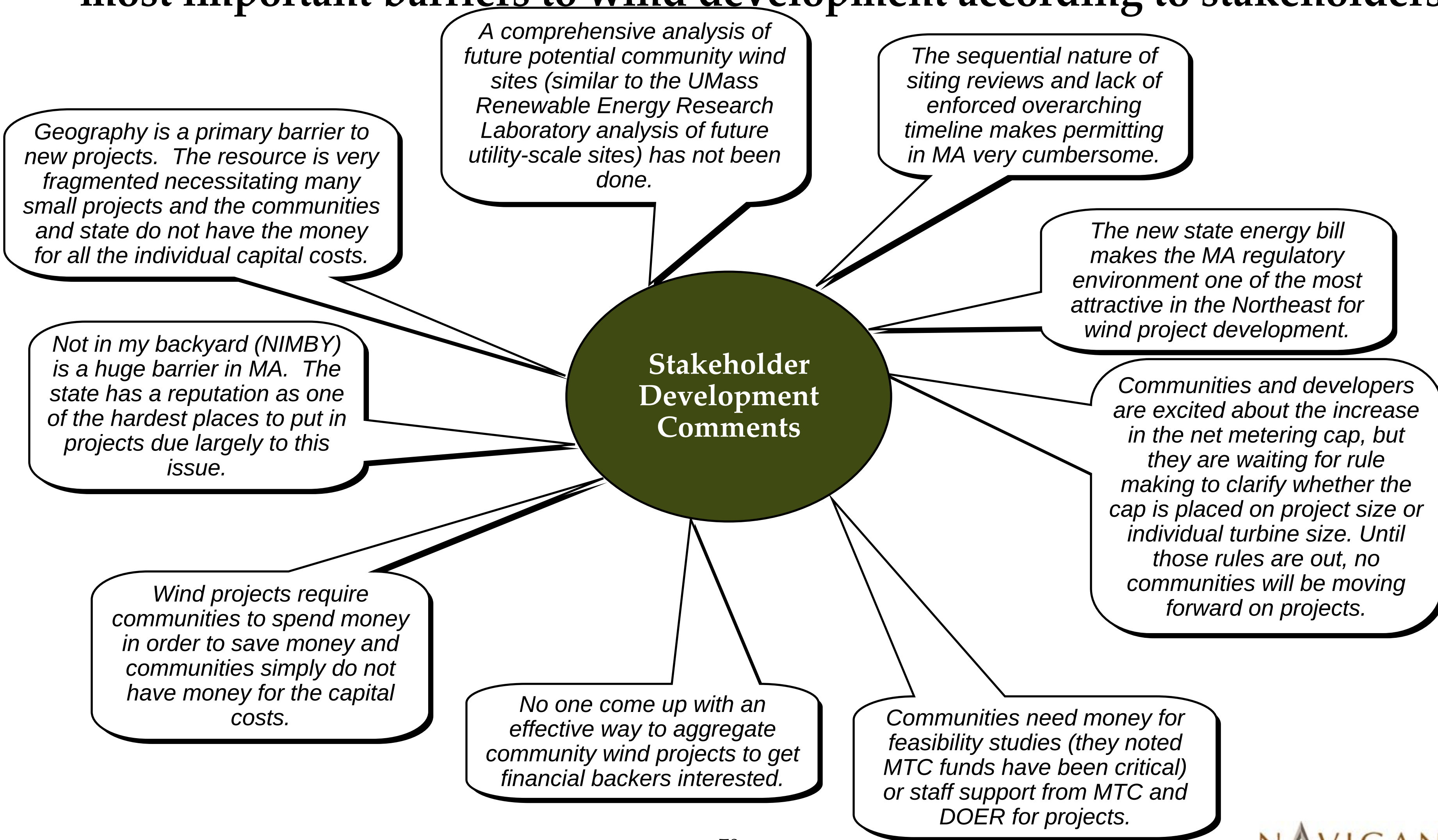
The timeline for developing onshore wind projects in MA can be lengthy and subject to many uncertainties.



- The project development timeline is highly variable in MA depending on:
  - Size: larger projects generally take longer (typical community-scale projects range from 12 to 36 months while utility-scale projects range from 2 to 4 years).
  - Local conditions: permitting is a local issue. If the local boards are familiar with wind, the process can move faster.
  - Skill of the developer: the keys are to hold public meetings upfront in the process to get early buy-in and avoid surprises and to be transparent with project data.
- Overall permitting process in MA is known as one of the most cumbersome processes across the states. Generally speaking the problem is that a strict timeline for the whole process is not set up and/or not followed. Many of the reviews are required to be sequential, so delays by one reviewing body delays the whole process.

NIMBY and the geography of the state and wind resource are the two most important barriers to wind development according to stakeholders.



A number of other barriers also exist that slow or prevent the market penetration of onshore wind power.

Technical	• Capacity factors in NE are the lowest in the nation and have not improved significantly over the years.[1] • The resource is very fragmented across the state leading to the need for smaller projects. • The resource also happens to be located in areas (i.e., beaches and ridgelines) that are likely to be protected habitats.
Economic	• MA is the 4th most densely populated state.[2] Combined with the fragmented resource, this makes large projects unlikely. Small sites reduce the ability to leverage project economies of scale. • Communities do not have the money to cover project capital costs, which makes projects difficult since much of the resource suits community-scale projects • Farm values in MA are the second highest in the country. In 2006, an acre of farm land cost an average of $11,600.[3] • Smaller projects make it harder to acquire wind turbines and secure operations and maintenance agreements.
Policy	• The lack of a clear and enforceable timeline at the beginning of the permitting process and the fact that many of the steps are sequential makes permitting process in MA one of the most difficult in the region.
Social	• NIMBY has been the single greatest barrier to wind project investment. Wind projects continue to be impacted by concerns about visual, noise, and property value impacts.[4]

Sources: 1.) *Annual Report on U.S. Wind Power Installation, Cost, and Performance Trends: 2007*, NREL, 2008; 2.) Cumulative Estimates of Population Change for the United States, States, and Puerto Rico - April 1, 2000 to July 1, 2007, U.S. Census, December 27, 2007. http://www.census.gov/popest/gallery/maps/maps-state2007.xls; 3.) The 2002 Agricultural Census, University of Massachusetts at Amherst, 2002, http://www.umass.edu/agcenter/census/real-estate.htm; 4.) Butterfield, S., Musial, W. and Ram, B. Energy from Offshore Wind.

In performing our analyses, NCI reviewed a number of reports and interviewed a number of wind industry participants.

- **Studies and Reports Reviewed:**
  - Commonwealth Wind Internal Planning Document: June 16, 2008 Briefing Agenda.
  - EERE: Wind and Hydro Technologies Program: Wind Powering America: New England Wind Forum (NEWF). May 2008 NE Wind Forum Vol1, Issue 4
  - EERE: Wind and Hydro Technologies Program: NEWF, MA activity. http://www.eere.energy.gov/windandhydro/windpoweringamerica/ne_astate_template.asp?stateab=ma
  - Elliot, D.L., et al., *Assessment of the Available Windy Land Area and Wind Energy Potential in the Contiguous United States*, Prepared by Battelle for U.S. DOE, August 1991.
  - Musial, Walt. (2005). Overview: Potential for Offshore Wind Energy in the Northeast. Presented at the Offshore Wind Energy Collaborative Workshop, February 10-11, 2005.
  - Renewable Energy Research Laboratory: UMass. "Memorandum, Subject: Massachusetts Potential Wind Sites Mapping Results." To: Seven Clarke, EEA, Diedre Matthews, MTC, and Chris Clark, MTC. April 29th, 2008.
  - Levitan and Associates, *Technical Assessment of Onshore and Offshore Wind Generation Potential in New England*, May 2007 and various comments/follow-ups to the report including the Industrial Wind Action Group's review, and the ISO NE Final Scenario Analysis Model Assumptions Presentation.
  - MTC's *Wind Project Pipeline Database,* Received June 26, 2008.
  - MTC/EEA's *Community Wind Sites Database*, Received June 30, 2008.
- **Wind Industry Participants Interviewed:**
  - Chris Clark, Program Manager, MTC
  - Steven Clarke, Clean Energy Technology Project Manager, Massachusetts Executive Office of Energy & Environmental Affairs
  - Maggie Downie, Assistant County Administrator for Barnstable County, Administrator for Cape Light Compact, Direct of Cand and Vineyard Electric Cooperative
  - A community wind developer who wishes to remain anonymous.

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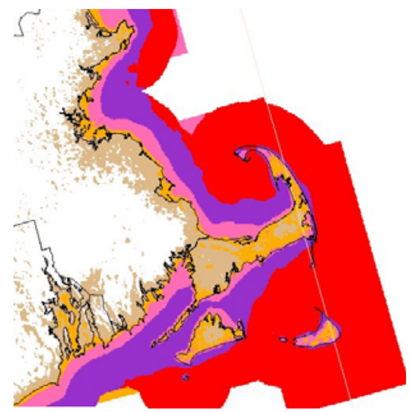
Offshore wind resources in MA range from good to outstanding (Class 4-6), but are still entirely untapped.

- Class 4[1] or better wind resources can be found along the entire MA coastline.
  - Significant technological, environmental and regulatory barriers exist, which has hindered offshore wind development in MA.
  - Barriers for near-shore projects in state waters differ compared to those in federal waters (over 3 miles offshore) based on economic, technology, environmental, social, and regulatory issues.
  - Deep sea projects, which are a subset of the federal waters tend to be dependent on technology innovation to make projects viable.
- Based on discussions with developers, researchers, and academics, it appears that no organization has done a comprehensive analysis of potential offshore wind sites in state or federal waters.



Wind Power Classification

Wind Power Class	Resource Potential	Wind Power Density at 50 m W/m 2	Wind Speed [a] at 50 m m/s	Wind Speed [a] at 50 m mph
1	Poor	0 - 200	0.0 - 5.6	0.0 - 12.5
2	Marginal	200 - 300	5.6 - 6.4	12.5 - 14.3
3	Fair	300 - 400	6.4 - 7.0	14.3 - 15.7
4	Good	400 - 500	7.0 - 7.5	15.7 - 16.8
5	Excellent	500 - 600	7.5 - 8.0	16.8 - 17.9
6	Outstanding	600 - 800	8.0 - 8.8	17.9 - 19.7
7	Superb	> 800	> 8.8	> 19.7

[a] Wind speeds are based on a Weibull k value of 2.0

1. Higher wind class is better, with Class 3 typically considered the minimum required for wind power development. At 50m wind speeds: Class 6 = 8.0-8.8 m/s (17.9-19.7 mph); Class 5 = 7.5- 8.0m/s (16.8-17.9 mph); Class 4 = 7.0-7.5m/s (15.7-16.8 mph);

Installed costs of a 300 MW offshore wind in MA are estimated to $5,400/kW. NCI examined two different moderate cost declines.

	Offshore Wind Power Economic and Performance Assumptions for Given Year of Installation (2008$)		
	2008 market/supported/acc	**2012** market/supported/acc	**2020** market/supported/acc
Plant Capacity (MW)[1]	300 / 300 / 300	300 / 300 / 300	300 / 300 / 300
Project Life (yrs)	25 / 25 / 25	25 / 25 / 25	25 / 25 / 25
Total Installed Cost ($/kW)[2]	$5,400 / $5,400 / $5,400	$4,990 / $5,296 / $4,990	$4,240 / $4,880 / $4,240
Fixed O&M ($/kW-yr)[2]	$15 / $15 / $15	$15 / $15 / $15	$15 / $15 / $15
Non-fuel variable O&M ($/MWh)[2]	$20 / $20 / $20	$14 / $17 / $14	$8 / $14 / $8
Net Capacity Factor (%)[3]	39% / 39% / 39%	39% / 39% / 39%	39% / 39% / 39%

Sources: NCI Estimates 2008. Rogers, et al. A Fresh Look at Offshore Wind Opportunities in Massachusetts, UMass at Amherst, May 2000; Renewable Energy Costs of Generation Inputs for IEPR 2007, April 2007, prepared for CEC/PIER; EERE New England Wind Forum; U.S. Department of Energy, Energy Efficiency and Renewable Energy (EERE), *20% Wind Energy by 2020: Increasing Wind Energy's Contribution to U.S. Electricity Supply,* May 2008; U.S. Department of the Interior, Minerals Management Services (MMS), Cape Wind Energy Project Draft EIS, January 2008; Interviews with developers, regulators, consultants, and academics.

1. The plant capacity is for a mid-level large offshore wind project.
2. NCI cost estimates are based on interviews. Under the high renewable energy cost setting, costs flatten to 2010, followed by a decline of 1%/yr after 2010 based on increased turbine supply and stabilizing commodity prices. A cost decline of 1%/yr between 2008 and 2010 followed by a 2%/yr decline to 2020 was assumed for the low renewable energy cost setting. Fixed and non-fuel O&M costs are based on the EERE report.
3. Projects were modeled individually with each one having its own capacity factor. The capacity factors ranged for the seven large projects modeled ranged from 25% to 39%. The capacity factor shown here comes from the MMS *Cape Wind Energy Project Draft EIS* (Horseshoe Shoal project capacity factor).

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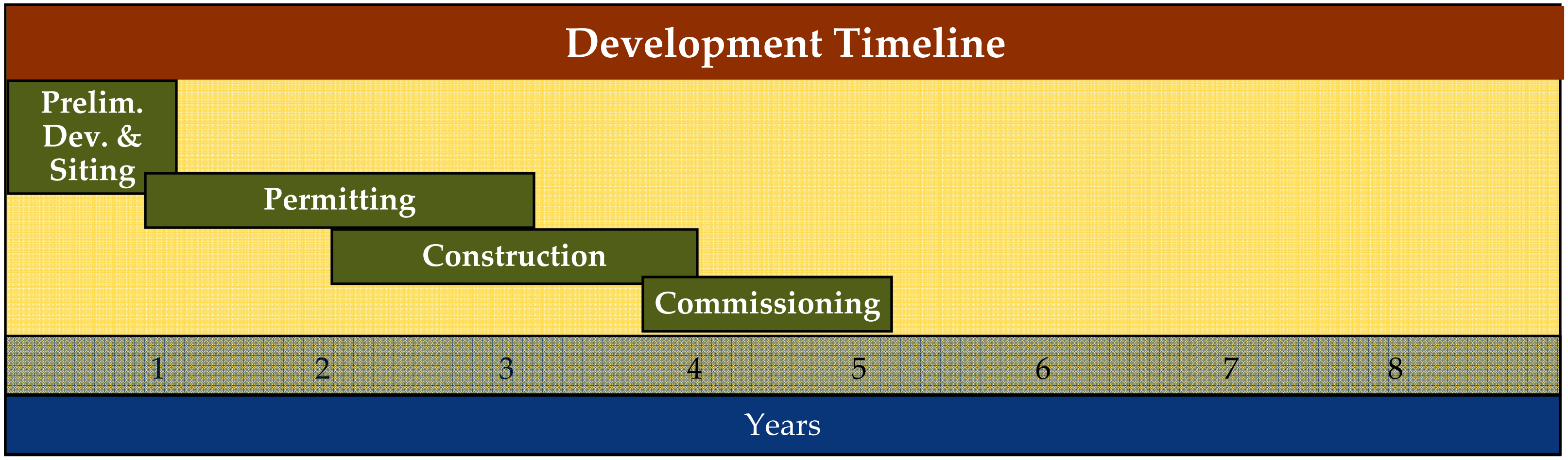
Installed costs of a 40 MW offshore wind in MA are now close to $4,000/kW. NCI examined two different moderate cost declines.

	Offshore Wind Power Economic and Performance Assumptions for Given Year of Installation (2008$)		
	2008 **market/supported/acc**	**2012** **market/supported/acc**	**2020** **market/supported/acc**
Plant Capacity (MW)[1]	40 / 40 / 40	40 / 40 / 40	40 / 40 / 40
Project Life (yrs)	25 / 25 / 25	25 / 25 / 25	25 / 25 / 25
Total Installed Cost ($/kW)[2]	$4,000 / $4,000 / $4,000	$3,692 / $3,892 / $3,692	$3,140 / $3,620 / $3,140
Fixed O&M ($/kW-yr)[2]	$15 / $15 / $15	$15 / $15 / $15	$15 / $15 / $15
Non-fuel variable O&M ($/MWh)[2]	$20 / $20 / $20	$14 / $17 / $14	$8 / $14 / $8
Net Capacity Factor (%)[3]	37% / 37% / 37%	37% / 37% / 37%	37% / 37% / 37%

Sources: NCI Estimates 2008. Rogers, et al. A Fresh Look at Offshore Wind Opportunities in Massachusetts, UMass at Amherst, May 2000; Renewable Energy Costs of Generation Inputs for IEPR 2007, April 2007, prepared for CEC/PIER; EERE New England Wind Forum; U.S. Department of Energy, Energy Efficiency and Renewable Energy (EERE), *20% Wind Energy by 2020: Increasing Wind Energy's Contribution to U.S. Electricity Supply*, May 2008; U.S. Department of the Interior, Minerals Management Services (MMS), *Cape Wind Energy Project Draft EIS*, January 2008; Interviews with developers, regulators, consultants, and academics; Manwell, et al., *Status Report on the Hull Offshore Wind Project*, Windpower 2007 Conference.

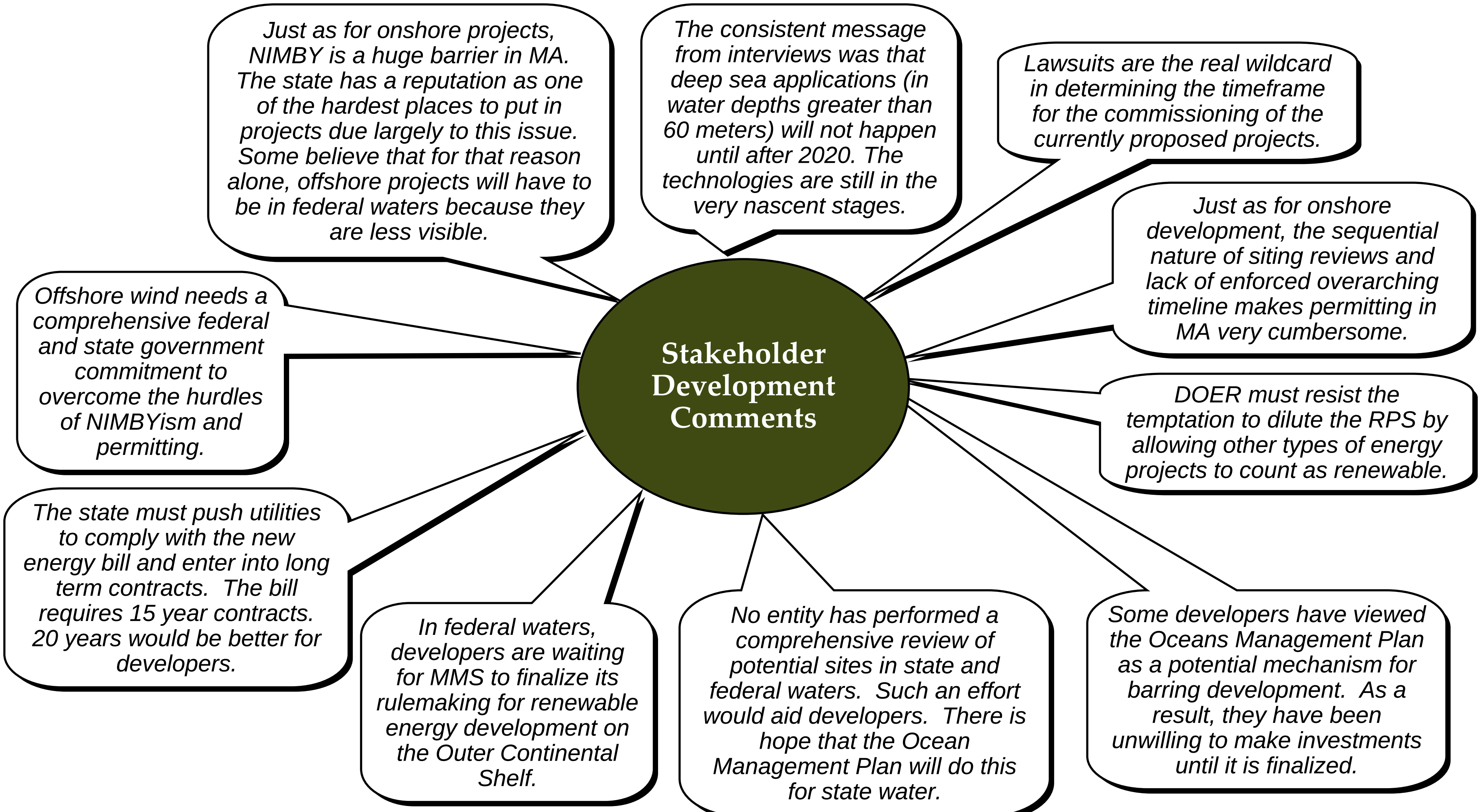
1. The plant size is for a relatively large version of a near shore project.
2. NCI cost estimates are based on interviews. The reasons the installed costs appear lower for these smaller offshore projects compared to the larger offshore projects is that the proposed smaller sites are in closer proximity to shore reducing the required length of undersea cable, which costs anywhere from 1.5 to 4 million $/mile, and because of the smaller number of linkages needed within the array (due to the far fewer number of turbines). Under the high renewable energy cost setting, costs flatten to 2010, followed by a decline of 1%/yr after 2010 based on increased turbine supply and stabilizing commodity prices. A cost decline of 1%/yr between 2008 and 2010 followed by a 2%/yr decline to 2020 was assumed for the low renewable energy cost setting. Fixed and non-fuel O&M costs are based on the EERE report.
3. Capacity factors for the four smaller projects ranged from 33% to 41%. The capacity factor shown here is for the Hull Offshore wind project taken from Manwell, et al., 2007.

The timeline for developing onshore wind projects in MA can be lengthy and subject to many uncertainties.



- This timeline is based on conversations with key developers and regulators, and it is the proposed timeline once the regulatory process is finalized in both state waters (the Oceans Management Plan is due out in 2009) and federal waters (the Minerals Management Service is due to complete there final rulemaking on development by the end of 2008). Up until this point, the timeline has been longer (Cape Wind has been in the works for 8 years).
- Factors that contribute to uncertainty in the timeline for any given project include:
  - Potential lawsuits that can slow projects down. This is particular concern in MA, where strong NIMBY attitudes have burdened the industry tremendously.
  - Overall permitting process in MA is known as one of the most cumbersome processes across the states. Generally speaking the problem is that a strict timeline for the whole process is not set up and/or not followed. Many of the reviews are sequential, so delays by one reviewing body delays the whole process.

NIMBY and regulatory uncertainty are the two most important barriers to wind development, based on stakeholder interviews.



A number of other barriers also exist that slow or prevent the market penetration of offshore wind power.

Technical	• Commercial deepwater technology is 10-15 years away.[1] Engineering standards work for the well known monopile offshore structures took eight years to develop. Work has not even begun on deep sea applications. • Ability to predict loads and resulting dynamic responses of the turbine and support structure when subjected to wave and wind loading is necessary. • Beyond 15 miles, DC current interconnection cable is required, which is more expensive than normal AC lines. • Shifting sandy shoals and seabed slopes make turbine installation difficult and potentially risky. • No group has performed a prescreening of potential sites in state and federal waters. • Locations of US Navy/Coast Guard ordinances restrict wind farm development in some areas.[2]
Economic	• O&M model for offshore wind must be re-orchestrated. Onshore model of frequent maintenance visits is uneconomical for offshore installations. Need for harbor space for maintenance and repair.[2] • Significant deep water exists off most of the coast with shallow water mainly in harbors, where significant human resistance exists. The deeper the water, the greater the cost of the system.
Policy	• The lack of a clear and enforceable timeline at the beginning of the permitting process and the fact that many of the steps are sequential makes permitting process in MA one of the most difficult in the region. • Regulatory uncertainty prior to the development of the Oceans Management Plan and finalization of the MMS development rules has developers waiting. • Ambiguities in the Ocean Sanctuaries legislation need to be resolved before development can occur in Nantucket Sound[3]
Social	• Based on a Cape Cod survey, social concerns include: negative impact of marine life, aesthetics, fishing, boating and yachting safety[3] • Potential lawsuits stemming from NIMBYism are a real concern.

Sources: 1. Musial, Walt. (2005). *Overview: Potential for Offshore Wind Energy in the Northeast.* 2. Rogers, et al. *A Fresh Look at Offshore Wind Opportunities in Massachusetts*. 3. Butterfield, S., Musial, W. and Ram, B. *Energy from Offshore Wind*. Conference Paper: NREL/CP-500-39450, February 2006.

In performing our analyses, NCI reviewed a number of reports and interviewed a number of wind industry participants.

- **Studies and Reports Reviewed:**

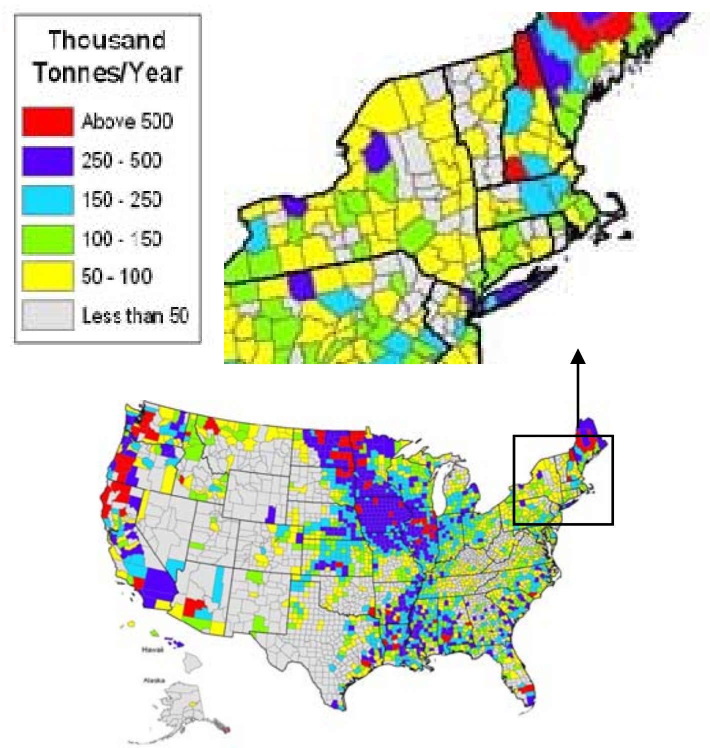
  - Butterfield, S., Musial, W. and Ram, B. Energy from Offshore Wind. Conference Paper: NREL/CP-500-39450, February 2006.
  - Commonwealth Wind Internal Planning Document: June 16, 2008 Briefing Agenda.
  - EERE: Wind and Hydro Technologies Program: Wind Powering America: New England Wind Forum (NEWF). May 2008 NE Wind Forum Vol1, Issue 4
  - EERE: Wind and Hydro Technologies Program: NEWF, MA activity. http://www.eere.energy.gov/windandhydro/windpoweringamerica/ne_astate_template.asp?stateab=ma
  - Manwell, et al., Status Report on the Hull Offshore Wind Project, Renewable Energy Research Laboratory, University of Massachusetts, Amherst, Windpower 2007 Conference
  - Musial, Walt. (2005). Overview: Potential for Offshore Wind Energy in the Northeast. Presented at the Offshore Wind Energy Collaborative Workshop, February 10-11, 2005.
  - Musial, Walt. (2005, May 19). Offshore Wind Energy Potential for the United States. Retrieved June 25, 2008, from EERE Wind Powering America Publications database.
  - Rogers, et al. A Fresh Look at Offshore Wind Opportunities in Massachusetts. UMass at Amherst, May 2000.
  - TRC Environmental Corporation. Existing and Potential Ocean-Based Energy Facilities and Associated Infrastructure in Massachusetts. Prepared for the Massachusetts Office of Coastal Zone Management, June 26, 2006, RFR #: ENV 06 CZM 15
  - U.S. Department of Energy, Energy Efficiency and Renewable Energy (EERE), 20% Wind Energy by 2020: Increasing Wind Energy's Contribution to U.S. Electricity Supply, May 2008
  - U.S. Department of the Interior, Minerals Management Services, Cape Wind Energy Project Draft EIS, January 2008.

- **Wind Industry Participants Interviewed:**
  - Steven Barrett, Director, BlueWave Strategies, LLC
  - Nils Bolgen, Program Manager Clean Energy, MTC
  - Steven Clarke, Clean Energy Technology Project Manager, Massachusetts Executive Office of Energy & Environmental Affairs
  - Jim Manuel, University of Massachusetts at Amherst
  - Greg Watson, Massachusetts Executive Office of Energy & Environmental Affairs
  - Two offshore wind developers who wish to remain anonymous.

Forest residues and urban wood waste currently dominate the feedstock resources for biomass power in MA.

- Due to scarce agricultural residues MA overall biomass resources are not as robust as found in the agricultural Midwestern states.
- MA forest and urban wood waste account for the bulk of MA feedstock.
  - Urban wood waste is most abundant in eastern MA.
  - Forest residues dominate the resource mix in the western MA.
- Net forest growth presents a very large potential resource. Capturing this resource would entail the development of a significant forestry industry.
- Though energy crops (i.e. willow, hybrid poplar, switchgrass) do not currently contribute to the feedstock resource, there is potential for them to do so.

Biomass Resources Available in the United States[2]



1. Forest residues include residue from logging, land clearing, and unused forest growth.
2. Source: *Biomass Resources Available in the United States.* September, 2005. NREL. The study estimates the biomass resources currently available in the Unites States by county. It includes agricultural residues (crops and animal manure), wood residues (forest, primary and secondary mill, and urban wood), municipal discards, methane emissions form landfills, and domestic wastewater treatment, and dedicated energy crops on Conservation Reserve Program and Abandoned Mine lands.

Biomass direct combustion installed costs have risen rapidly over the past few years, with the potential for limited cost reductions ahead.

	Biomass Direct Combustion Economic and Performance Assumptions for Given Year of Installation (2008$)		
	2008 market/supported/acc	**2012** market/supported/acc	**2020** market/supported/acc
Plant Capacity (MW)[1]	50 / 50 / 50	50 / 50 / 50	50 / 50 / 50
Fuel Cost ($/MMBTU)	$2.75 / 2.75 / 2.75	$2.75 / 2.75 / 2.75	$2.75 / 2.75 / 2.75
Project Life (yrs)	25 / 25 / 25	25 / 25 / 25	25 / 25 / 25
Total Installed Cost ($/kW)[2]	$5,500 / 5,500 / 5,500	$5,165 / 5,380 / 5,165	$4,350 / 4,900 / 4,350
Fixed O&M ($/kW-yr)[3]	$145 / 145 / 145	$145 / 145 / 145	$145 / 145 / 145
Net Capacity Factor[4]	85% / 85% / 85%	85% / 85% / 85%	85% / 85% / 85%
Thermal Efficiency[4]	22% / 22% / 22%	23% / 23% / 23%	24% / 24% / 24%

Steel and other commodity price increases over the past several years have nearly doubled installed costs.

Sources: NCI Estimates 2008. Reviewed with biomass project developers, consultants and biomass industry experts.

1. Based on optimal size, balancing both installed cost and on-going fuel costs.
2. Total installed costs can vary widely depending on several factors, including local permitting requirements, grid interconnection, civil works. Key assumptions include: in the Supported Development scenario current installed costs on a $/kW basis remain flat through 2010 then decline by ~1% per year thereafter, reflecting moderating commodity prices and maturity of technology; in Accelerated Development and Market-Based Development scenarios costs decline by ~1% per year through 2010, then by ~2% per year thereafter.
3. O&M costs are based on interviews with industry.
4. Average expected capacity factor and thermal efficiency based on current technology; expected to remain fairly constant over time.

Gasification may see improved operating and financial results as technology improvements are implemented.

	Biomass Gasification Economic and Performance Assumptions for Given Year of Installation (2008$)		
	2008 market/supported/acc	**2012** market/supported/acc	**2020** market/supported/acc
Plant Capacity (MW)	50 / 50 / 50	50 / 50 / 50	50 / 50 / 50
Fuel Cost ($/MMBTU)	$2.75 / 2.75 / 2.75	$2.75 / 2.75 / 2.75	$2.75 / 2.75 / 2.75
Project Life (yrs)	25 / 25 / 25	25 / 25 / 25	25 / 25 / 25
Total Installed Cost ($/kW)[1]	$6,500 / 6,500 / 6,500	$5,065 / 5,380 / 5,065	$4,300 / 4,900 / 4,300
Fixed O&M ($/kW-yr)	$145 / 145 / 145	$145 / 145 / 145	$145 / 145 / 145
Net Capacity Factor	85% / 85% / 85%	85% / 85% / 85%	85% / 85% / 85%
Thermal Efficiency[2]	32% / 32% / 32%	37% / 37% / 37%	39% / 39% / 39%

Sources: NCI Estimates 2008. Reviewed with biomass project developers, consultants and biomass industry experts.

1. Key assumptions include: in the Supported Development scenario current installed costs on a $/kW basis remain flat through 2010 then decline by ~1% per year thereafter; in Accelerated Development and Market-Based Development scenarios costs decline by 2% per year through 2020.
2. Thermal efficiencies expected to improve over time as technology advancements are implemented.

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Co-firing's low installed costs make it potentially low-hanging fruit for the rapid implementation of additional renewable power capacity.

	Biomass Co-Firing Economic and Performance Assumptions for Given Year of Installation (2008$)		
	2008 market/supported/acc	**2012** market/supported/acc	**2020** market/supported/acc
Plant Capacity (MW)[1]	12 / 12 / 12	12 / 12 / 12	12 / 12 / 12
Fuel Cost ($/MMBTU)	$2.75 / 2.75 / 2.75	$2.75 / 2.75 / 2.75	$2.75 / 2.75 / 2.75
Project Life (yrs)	25 / 25 / 25	25 / 25 / 25	25 / 25 / 25
Total Installed Cost ($/kW)[2]	$300 / 300 / 300	$282 / 294 / 282	$238 / 270 / 238
Fixed O&M ($/kW-yr)	$22 / 22 / 22	$22 / 22 / 22	$22 / 22 / 22
Net Capacity Factor[3]	85% / 85% / 85%	85% / 85% / 85%	85% / 85% / 85%
Thermal Efficiency[3]	33% / 33% / 33%	33% / 33% / 33%	33% / 33% / 33%

Sources: NCI Estimates 2008. Reviewed with coal facility operators, consultants and biomass industry experts.

1. Based on 10% co-firing.
2. Assumes fluidized bed technology with separate feed system. In the Supported Development scenario current installed costs on a $/kW basis remain flat through 2010 then decline by ~1% per year thereafter; in Accelerated Development and Market-Based Development scenarios costs decline by ~1% per year through 2010, then by ~2% per year thereafter.
3. Average expected capacity factor and thermal efficiency based on current technology; expected to remain fairly constant over time.

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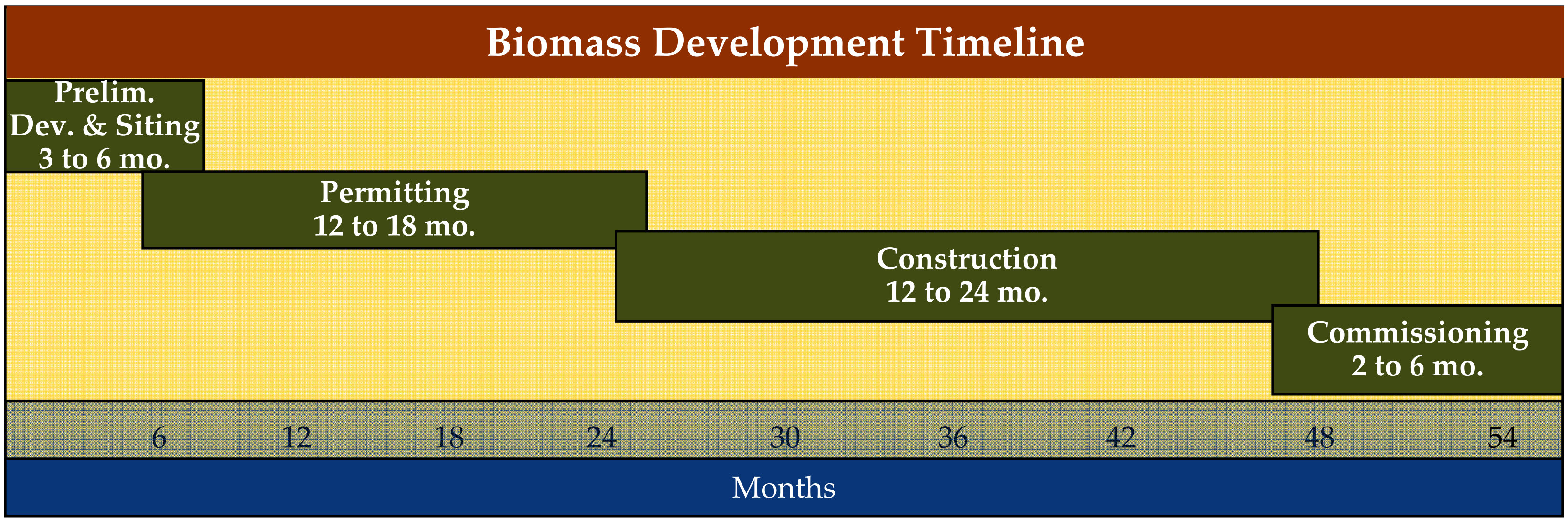
The timeline for developing biomass power projects in MA can range from about 3 years to 4.5 years, with initial facilities taking even longer.



- The stages depicted above may overlap, but tend to be sequential
- Principal issues causing uncertainty in the development timeline include:
  - Difficulties in securing early stage financing.
  - Preliminary siting requires attention to local receptivity, proximity to transmission, truck access, resource availability, and transport costs.
- One facility currently in development is faces a total development time of nearly seven years.

Length of the permitting timeline and difficulty in arranging long-term contracts and financing were repeatedly voiced as significant barriers to biomass power development.

Stakeholder Development Comments

Massachusetts is generally pretty biomass-friendly. There are not a ton of barriers, but the existing ones are big: REC market uncertainty, lack of a large forestry industry, permitting timeline.

Co-firing at coal plants in MA has significant obstacles and not likely to happen. Can't get RECs, have permitting issues. It's just not worth the hassle.

Local opposition can be a big barrier…

The question is not "is there enough wood," but "how expensive will it be to get it to plant in terms of transportation costs?"

Biomass facilities can have a strong local economic impact. You need 15-30 people to man the facility on a 24-hour basis, bringing permanent direct jobs. Also have the potential to stimulate 200-300 indirect jobs in forestry, logging and trucking.

There is a need for long-term contracts. Requiring utilities to sign long-term contracts for renewable power would be a great step…

Permitting requirements in MA aren't too bad, it just takes too long.

Support for existing forest industry (like sawmills) keeps around the people, and therefore the potential supply for biomass. Can't have biomass without an existing forest industry.

The lack of long-term REC contracting hampers biomass plant financing.

Feedstock supply and financing issues present significant barriers to biomass development.

Technical

- Lack of suitable quantities of feedstock supply (further exacerbated by financing constraints, discussed in Economic issues, below) may limit further biomass development.
  - Largest potential for expanding supply exists in the harvesting of net forest growth. Policies supporting growth of forestry industry—including low-interest loans for forestry equipment and worker training programs—could help increase security and quantity of feedstock supply.

Economic

- Capital costs have been rising rapidly over past several years, which may continue if steel and concrete prices and foreign demand for equipment increase.
- REC market lacks long-term (10 to 15 yr) contracting.
- Developers face difficulties in arranging financing for a variety of reasons:
  - Price risks on both ends: biomass feedstock and spot market on electricity
  - Long term (15 to 20 yr) power output contracts are ideal, but can be difficult to secure
  - Front end feedstock supply: the inability to secure long-term wood supply contracts is addressed through relationships with more wood suppliers than needed
- Policies mitigating financing risk could help remove significant barriers to development.

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Additional barriers arise due to community opposition and length of permitting timeline.

Policy

- Length of permitting timeline presents a significant issue for developers.
  - Streamlining process and timing would help reduce costs and time to market.
- Additional state policies that could address existing barriers include:
  - Coordination among states re: transmission and expedited permitting
  - Requiring utilities to sign long-term contracts for renewable power
  - Encouraging long-term REC off-take agreements
  - Ensuring RPS program continuity

Social

- Local opposition, largely in response to increased truck traffic in the community, can be a significant barrier.
  - However, this sentiment may be offset by the positive local economic impact of new direct and indirect jobs.

In performing the analyses, NCI reviewed a number of reports.

- *Biomass Energy Crops: Massachusetts' Potential*. Prepared for: Mass. DOER and Mass. Dept of Conservation & Recreation. Prepared by Univ. of Mass, Dept. of Resource Economics- David Timmons, Geoff Allen, David Damery. January 2008 ("Biomass: Mass. Potential")
- *Energy from Forest Biomass: Potential Economic Impacts in Massachusetts*. Prepared for Mass. DOER and Mass Dept. of Conservation and Recreation. Prepared by Univ. of Mass, Dept. of Resource Economics. David Timmons, David Dammery, Geoff Allen. Economic Development Research Group, Inc., Lisa Petraglia. December 2007.
- *Silvicultural and Ecological Considerations of Forest Biomass Harvesting in Massachusetts*. Prepared for the Mass. DOER and Mass Dept of Conservation & Recreation. Funding by U.S. DOE. Matthew Kelty, Anthony D'Amato, Paul Barten. Department of Natural Resources Conservation, Univ. of Mass., Amherst MA. January 2008.
- *Biomass Availability Analysis – Five Counties of Western Massachusetts. Renewable Biomass from the Forests of Massachusetts*. Prepared for the Mass. DOER and the Mass Dept of Conservation & Resources. With funding provided by the MTC. January 2007. Prepared by Innovative Natural Resource Solutions LLC.
- *The Woody Biomass Supply in Massachusetts: A Literature-Based Estimate*. Mass. Biomass Energy Working Group Supply Subcommittee. Prepared by Fallon & Breger. Amherst, MA, under contract to DOER & Dept. of Environmental Management. May 2002.
- *Advanced Biopower Technology Assessment*. Prepared for the Mass. DOER & Mass. Dept. of Conservation & Recreation. Funded by MTC & Renewable Energy Trust. Prepared by Black & Veatch. January 2008.
- *Biomass Availability Analysis – Worcester, MA. Renewable Biomass from the Forests of MA*. Prepared for DOER & DCR, with funding provided by the MTC. January 2007. Prepared by Innovative Natural Resource Solutions LLC.

In performing the analyses, NCI reviewed a number of reports, continued.

- *Biomass Availability Analysis – Pittsfield, MA. Renewable Biomass from the Forests of MA*. Prepared for DOER & DCR, with funding provided by the MTC. January 2007. Prepared by Innovative Natural Resource Solutions LLC.
- *Biomass Availability Analysis – Springfield, MA. Renewable Biomass from the Forests of MA*. Prepared for DOER & DCR, with funding provided by the MTC. January 2007. Prepared by Innovative Natural Resource Solutions LLC.
- "Massachusetts Potential for Biomass Energy Crops - Regional Economic Impact Analysis: Energy from Forest Biomass." David T. Damery, Ph.D., David Timmons,Geoffrey Allen. University of Massachusetts, Amherst. Department of Natural Resources Conservation. Department of Resource Economics.
- *A Geographic Perspective on the Current Biomass Resource Availability in the United States.* A. Milbrandt. NREL/TP-560-39181. December 2005.
- Northeast Regional Biomass Program. 2007 spreadsheet showing feedstock estimates for all states, including MA: http://www.nrbp.org/updates/2007-08/US_Biofuel_Production_Potential.xls.
- *Woody Biomass to CHP - Characteristics, Costs, and Performance of Commercially Available Technologies*. Kim Crossman. U.S. EPA CHP Partnership. Presented to the Society of American Foresters, October 26, 2007.
- *Annual Energy Outlook 2008*. Energy Information Administration. 2008.
- *Advanced Biofuels Task Force Report*. Commonwealth of Massachusetts. Spring 2008.

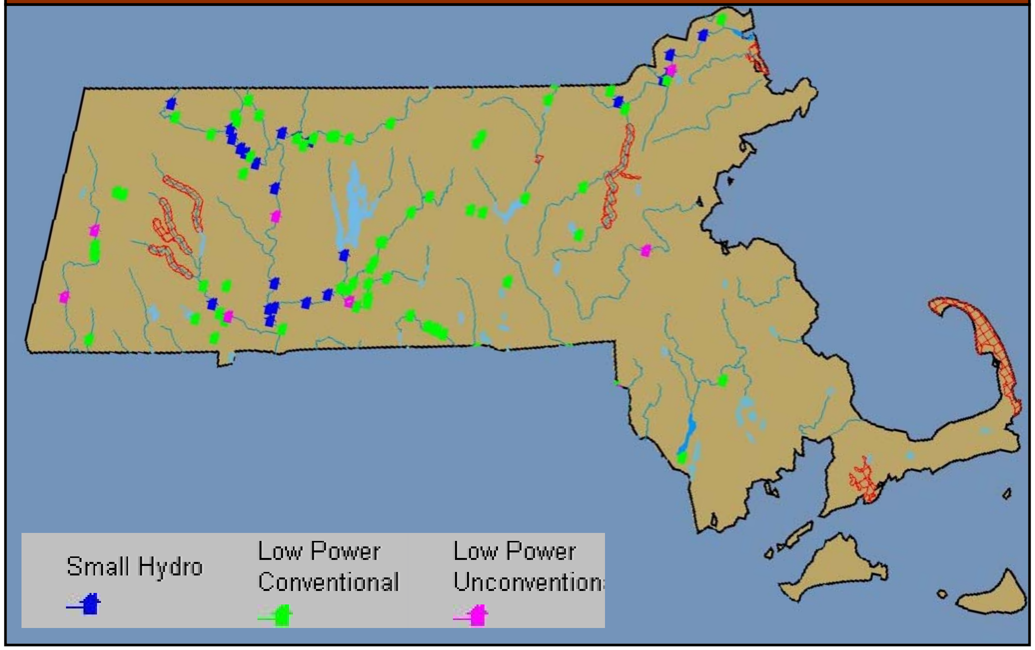
In performing the analyses, NCI also interviewed a number of biomass industry participants.

- A coal facility participant who wishes to remain anonymous.
- A number of renewable energy developers who wish to remain anonymous.

Hydro resources in Massachusetts are limited, and the best sites have already been developed.

- The total hydropower resource in Massachusetts has been estimated by the Idaho National Laboratory at ~540 MW, of which ~260 MW has been developed.[1]
- Gomez and Sullivan characterized the small hydro sector in 2007 for MTC
  - 45 potential sites were identified, totaling 11.5 MW
  - All but one at existing dam structures
  - Project sizes range from 0.056 MW to 1.191 MW
  - The average size is 0.256 MW and the median is 0.173 MW.[2]
- In addition to new capacity, rehabilitation of existing infrastructure will contribute to new GW and GWh.

Potential Hydropower Sites Identified by INL in MA



Source: INL, *Virtual Hydropower Prospector*.

1. Idaho National Laboratory, Feasibility Assessment of the Water Energy Resources of the United States for New Low Power and Small Hydro Classes of Hydroelectric Plants, January 2006. DOE-ID-11263.
2. Gomez and Sullivan, memo to MTC, "Characterization of the Small Hydropower Sector in Massachusetts," March 6, 2007.

The total FERC Licensed, Exempt, and Non-Jurisdictional Hydro Projects in Massachusetts that is not pumped hydro is 284 MW.

FERC Licensed, Exempt, and Non-Jurisdictional Hydro Projects in MA		
	Sites	**MW**
> 25 MW	3	144
10 – 24 MW	3	59
1 – 9 MW	22	63
< 1 MW	45	17
Total	**73**	**284**

The average plant size is 3.9 MW with a median of 0.70 MW.

Source: Gomez and Sullivan, memo to MTC, "Characterization of the Small Hydropower Sector in Massachusetts," March 6, 2007.
NCI analysis of Table 1: FERC Licensed, Exempt, and Non-Jurisdictional Hydropower Projects in Massachusetts.
Note: There are two pumped hydro energy storage sites: 1,000 MW and 611 MW.

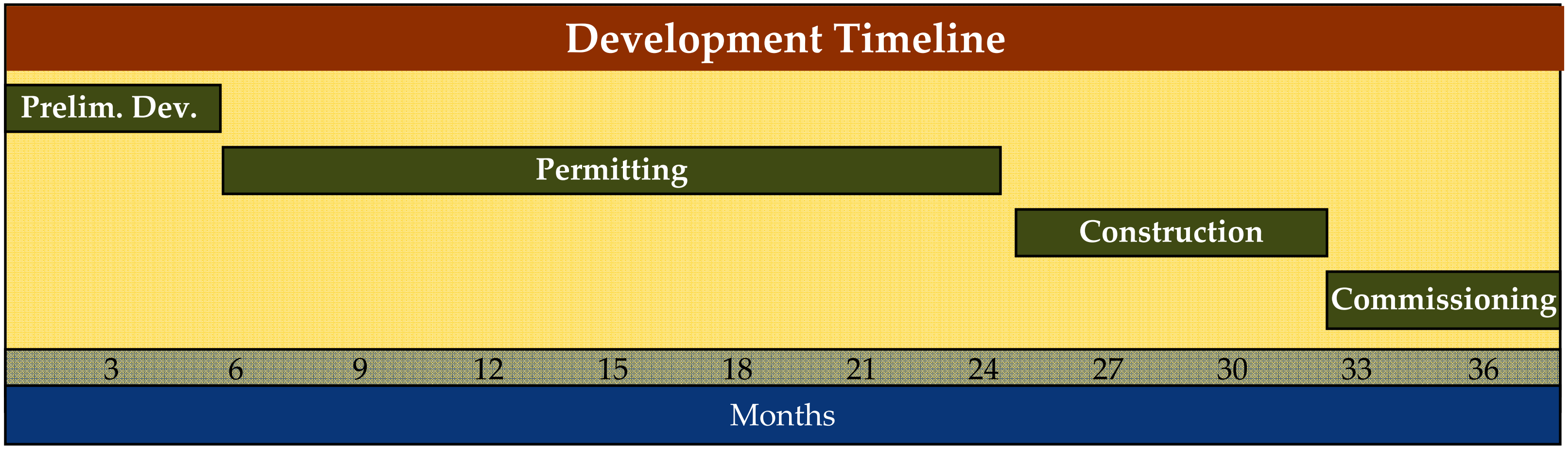
Installed costs of small hydro with a dam in place are now close to $4,800/kW. A moderate decrease is expected beyond 2012 due to lower commodity costs.

	Small Hydro Power Economic and Performance Assumptions for Given Year of Installation (2008$)		
	2008 market/supported/acc	2012 market/supported/acc	2020 market/supported/acc
Plant Capacity (MW)[1]	1 / 1 / 1	1 / 1 / 1	1 / 1 / 1
Project Life (yrs)	25 / 25 / 25	25 / 25 / 25	25 / 25 / 25
Total Installed Cost ($/kW)[2]	$4,800 / $4,800 / $4,800	$4,620 / $4,720 / $4,620	$4,100 / $4,400 / $4,100
Fixed O&M ($/kW-yr)[2]	$24 / $24 / $24	$24 / $24 / $24	$24 / $24 / $24
Non-fuel variable O&M ($/MWh)[2]	$5.50 / $5.50 / $5.50	$5.50 / $5.50 / $5.50	$5.50 / $5.50 / $5.50
Net Capacity Factor (%) [3]	48.4% / 48.4% / 48.4%	48.4% / 48.4% / 48.4%	48.4% / 48.4% / 48.4%

Sources: NCI Estimates 2008. CEC PIER "Statewide Small Hydropower Resource Assessment"; PIER Final Project Report, June 2006. Idaho National Laboratory "Estimation of Economic Parameters of U.S. Hydropower Resources," June 2003; INEEL Hydropower Resource Economics Database (IHRED); Natural Resources Canada RETScreen® Energy Model – Small Hydro Project; "Feasibility Assessment of the Water Energy Resources of the United States for New Low Power and Small Hydro Classes of Hydroelectric Plants" U.S. Department of Energy, Energy Efficiency and Renewable Energy Wind and Hydropower Technologies. Reviewed with project developers and owners.

1. According to the June 2006 PIER report, the median project size is approximately 1 MW for small hydropower.
2. Actual installed costs vary widely based on the amount of civil works and mitigation required. NCI cost estimates are based on Idaho National Lab and RETScreen estimates for a 1 MW facility where the dam is already in place, as well as discussions with MA project developers. Many of the best small hydro resources have already been developed in MA. The remaining sites will be small and nonstandard, requiring custom design, and may present siting and permitting complications. These factors have the potential to offset decreased costs due to future technology improvements. An approximate 1% decline after 2012 is estimated due to declining commodity costs.
3. Idaho National Laboratory Hydropower Estimates; Average annual capacity factor MA

FERC has adapted its procedures to condense the timeline for developing small hydro projects to 2-3 years.



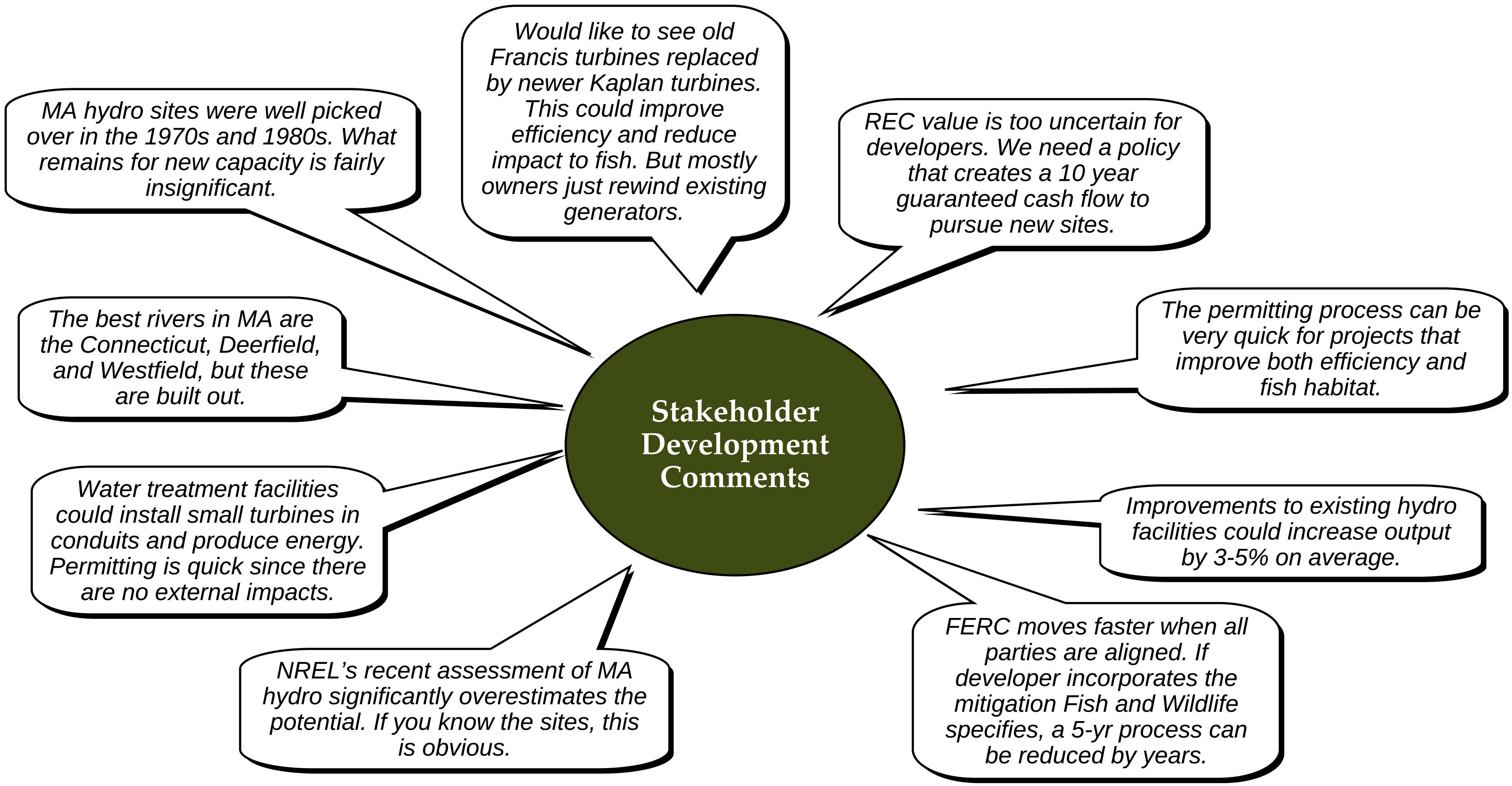
- Developers must obtain a FERC permit and a 401 State Water Quality Certificate from DEP within one year of applying to FERC.
- FERC has shortened comment periods to 60 days, and may require an Environmental Impact Report, not a full Environmental Impact Assessment, for small projects.
- Permitting is highly site specific.
  - Large projects (>5 MW) require FERC license, which is granted for 30-50 years and can take 5 years to obtain.
  - Projects 5 MW or less at an existing dam can apply for an exemption, which is issued in perpetuity. However, these projects are subject to MA Fish and Game requirements for the life of the project.

FERC has identified the factors that lead to expedited permitting for small hydro.

Factors That Reduce Time and Cost	How FERC May Expedite the Process
• Project at existing dam • Little change to water flow and use • Unlikely to: affect threatened and endangered species, or need fish passage • Applicant owns all lands needed for project construction and operation • Information on existing environmental resources and project effects are readily available	• With state resource agency cooperation, waive some pre-filing consultation requirements • Combine scoping of issues with pre-filing consultation • Combine public noticing requirements • Shorten comment periods • Use a single environmental document in lieu of draft and final documents

Source: FERC Guide to Developing Small/Low Impact Hydropower Projects

Both industry and regulators are focused on improving existing sites rather than pursuing new capacity.



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Beyond limited resource potential, a number of barriers prevent development of remaining sites.

Technical	• DOE is funding development of "fish friendly" Kaplan turbines. Costs and performance are being evaluated. When commercially available, these turbines are expected to improve efficiency and reduce or eliminate impact.
Economic	• Permitting costs can still be $50-100k for small projects that qualify for a licensing exemption, for small hydro projects of 100 kW these costs add $500/kW to $1,000/kW to the overall cost. • Long term financial incentives are needed, especially for small projects where fixed costs can be high relative to project output.
Policy	• Developers do not always know which sites can be developed. State agencies can identify sites that would be most favorable from a permitting perspective.
Social	• Environmental issues most often slow new hydro development. Conflicts with anadromous fish passage can stall or make mitigation costs prohibitive for small projects.

In performing our analyses, NCI reviewed a number of reports and interviewed several hydro energy industry participants.

- Studies and reports reviewed:
  - Gomez and Sullivan, memo to MTC, "Characterization of the Small Hydropower Sector in Massachusetts," March 6, 2007
  - INL, *U.S. Hydropower Resource Assessment for Massachusetts*, July 1995.
  - INL, *Feasibility Assessment of the Water Energy Resources of the United States for New Low Power and Small Hydro Classes of Hydroelectric Plants*, January 2006
  - *International Small Hydro Atlas - United States.* http://www.small-hydro.com/index.cfm?Fuseaction=countries.country&Country_ID=82
  - INL, Virtual Hydropower Prospector, http://hydro2.inel.gov/prospector/r_selector.shtml
  - INL, *Estimation of Economic Parameters of U.S. Hydropower Resources*, June 2003.
- Hydro industry participants interviewed:
  - Russ Cohen, MA Department of Fish and Game, Riverways Division
  - Caleb Slater, MA Department of Fish and Game, Anadromous Fish
  - Tom Tarpey, Bay State Hydropower Association

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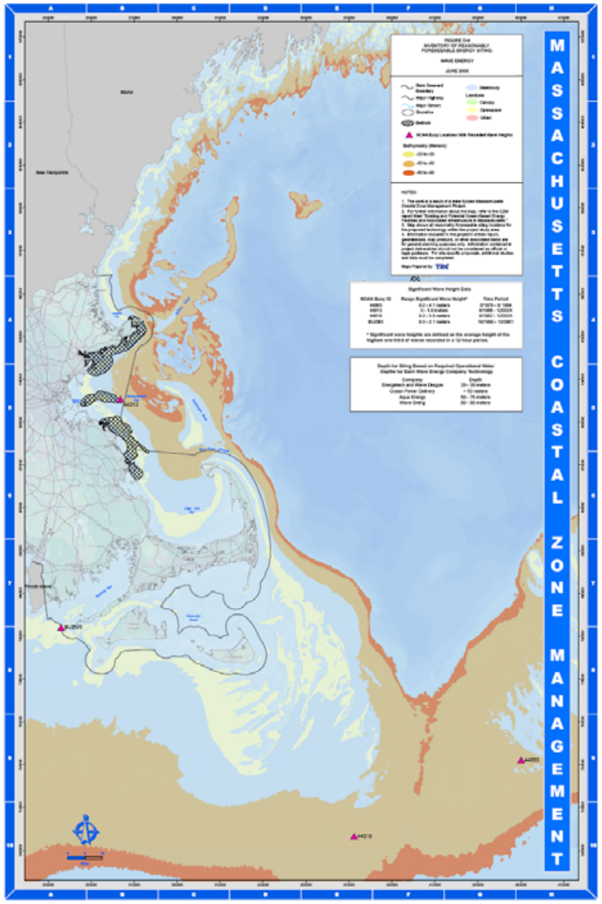
9	**Appendices**
1	Incentives
2	Onshore Wind
3	Offshore Wind
4	Biomass
5	Small Hydro
6	**Wave & Tidal**

Wave resources in Massachusetts are limited, with the greatest potential at sites around the Cape and Islands.

- Wave resources are assessed based on average wave power density which is a function of maximum significant wave height and maximum significant wave period.
- Truro was selected by EPRI as an attractive site, but annual data show the summer wave resource is half that of winter, which is opposite the area load profile.
- Relative to other locales nationwide the Truro site is not likely to be developed in the near term because it has approximately half of the wave energy of sites on the west coast of the US.
- To date, no utility or private developer has stepped up to pursue development of a pilot at the Truro site.

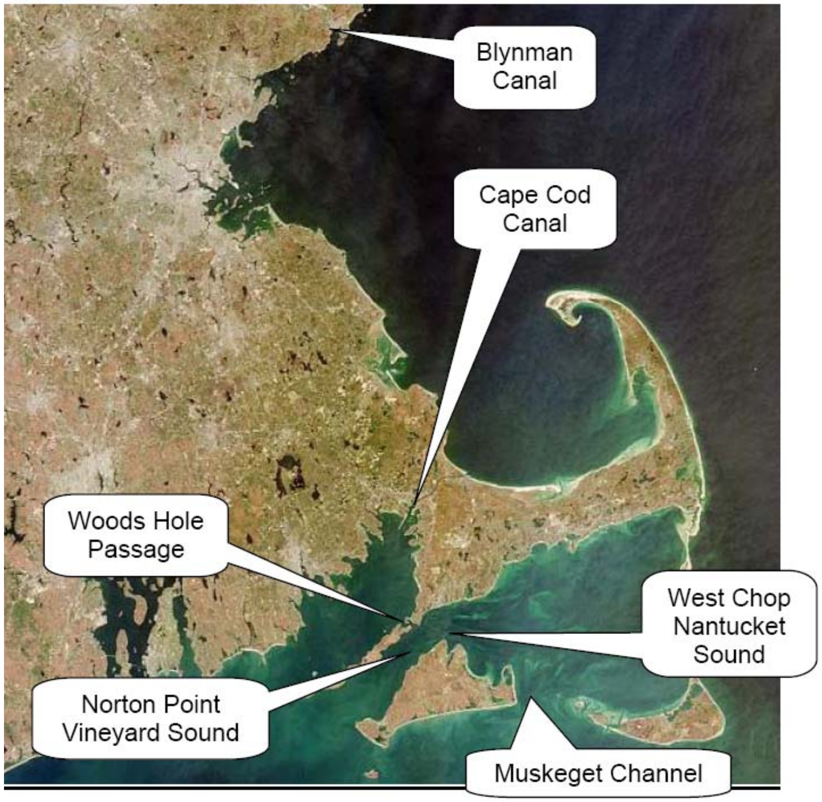


Source: *Existing and Potential Ocean-Based Energy Facilities and Associated Infrastructure in Massachusetts*, TRC Environmental Corporation for MA Office of CZM, June 26, 2006.

The greatest tidal energy potential in Massachusetts is around the Cape and Islands.

- Tidal current surface velocities must average a minimum of 1.5 m/s (3 knots) for consideration.
- Six sites were selected by EPRI that meet this criterion. It is extremely unlikely that other sites would be identified on the coastline, as it would require a significant technology breakthrough. The six sites were further evaluated for:
  - Bathymetry and seafloor geometry
  - Potential for utility grid connection
  - Maritime support infrastructure
  - Environmental considerations, and
  - Unique opportunities.
- Of the six sites, three are being developed.
  - EPRI identified **Muskeget Channel** as the site of choice for the technology test bed. Although one of the top options, EPRI estimates its maximum capacity at 4 MW.
  - Developers are also currently pursuing the **Cape Cod Canal**. Cape Cod Canal is the strongest resource, but navigation is a complicating factor; developers are currently trying to address this issue.
  - **Vineyard Sound**'s energy density is relatively low, but this site is still being pursued.

Potential TISEC Project Sites Surveyed by EPRI



Source: EPRI, *Massachusetts Tidal In-Stream Energy Conversion (TISEC): Survey and Characterization of Potential Project Sites*, October 2006.

No wave or tidal capacity has been installed in Massachusetts, though at least three tidal projects are under development.

Tidal Capacity – Under Development				
Location	**Developer**	**Pilot (MW)**	**Commercial (MW)**	**Comment**
Muskeget Channel	Town of Edgartown	1-2	6-20	Preliminary Permit approved by FERC. Developer has applied for funding from DOE as a technology test bed, using several available turbines during pilot. Long term, the site could provide 6 to 20 MW of power.
Vineyard Sound	Massachusetts Tidal Energy Company (Oceana Energy Co.)	1-5	15-50	Preliminary Permit approved by FERC. Feasibility study is underway. Navigation constraints will limit commercial-scale project size, which could range from 15 to 50 MW.
Cape Cod Canal	Natural Currents Energy Services	1-5	10+	Cape Cod Canal is operated by the federal government, so seeking a FERC pilot license to build. May begin with small 25 kW Red Hawk turbines (up to 40) on bridge footings, and test 1 MW and 5 MW turbines longer term.

FERC now requires that all ocean power projects be developed first as pilots due to technology risk.

Note: There are no wave projects currently under development in Massachusetts.

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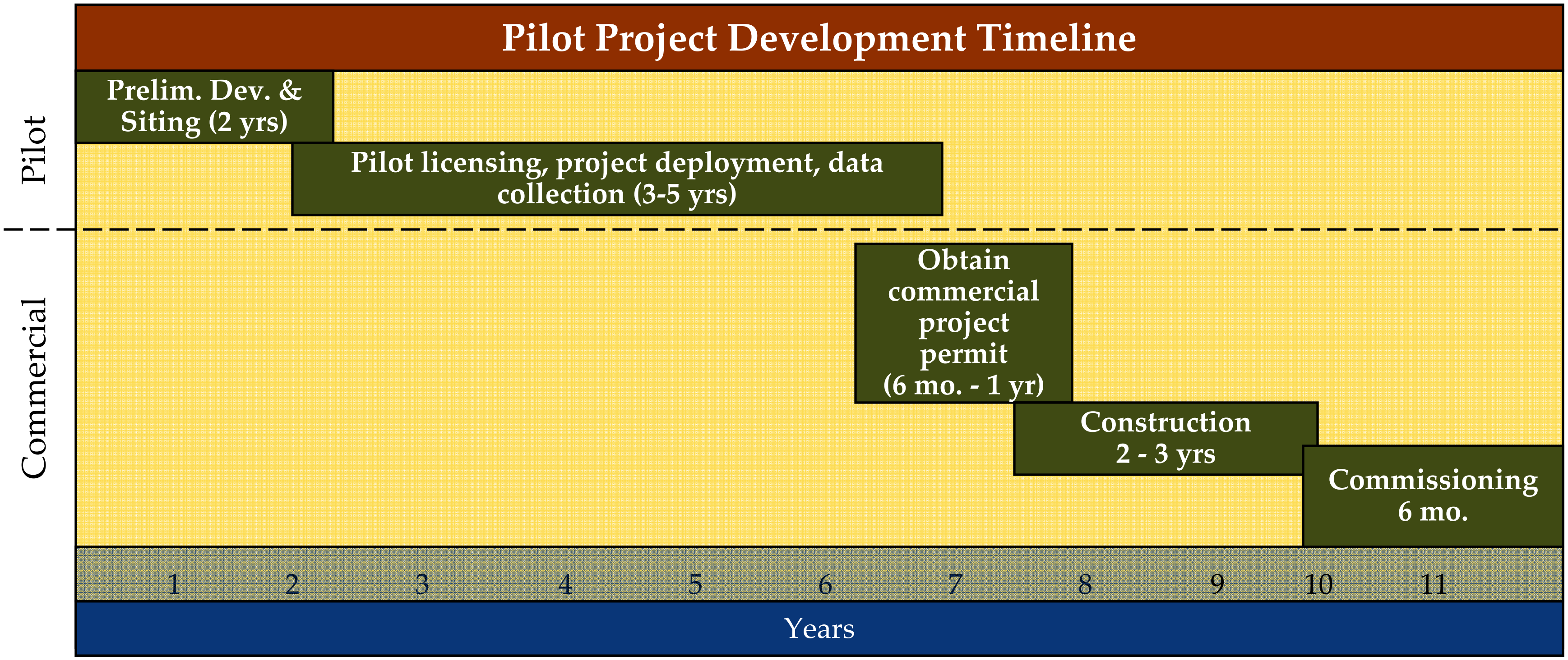
The timeline for developing ocean energy projects in MA is lengthy and subject to many uncertainties.



- 1 year for FERC to process Preliminary Permit, which locks in site for 3 years; 1 year for feasibility study
- 3 to 5 years for pilot licensing; deployment and data collection at site
- Apply for commercial project license during pilot as data is developed
- 6 months to 1 year to obtain commercial project permit
- Then enter construction and commissioning phase for commercial-scale project.

FERC has recently created a faster permitting process and in MA the MA Oceans Act will reduce complexity at the state-level.

Permitting: Current Processes and Future Impacts		
Future Impacts on Permitting	**State**	• Massachusetts Oceans Act of 2008: — The Oceans Act became MA law on May 28, 2008. It aims to regulate offshore development in the 3 miles between state coastline and federal waters including fishing, tourism, energy, and other interests. The legislation establishes a management plan and charges officials, industry and environmental stakeholders with examining projects based on shore proximity, environmental impact, community benefit, and other criteria. The Act will be incorporated into the existing CZM plan and enforced through the state's regulatory and permitting processes, including the Massachusetts Environmental Policy Act (MEPA) and Chapter 91. — The bill amends section 15 of the Ocean Sanctuaries Act to allow for the siting of "appropriate scale" offshore renewable energy facilities in state waters except for the Cape Cod Ocean Sanctuary (offshore from the Cape Cod National Seashore on the Outer Cape) provided that the facility is consistent with the ocean plan. — Though this aspect of the law benefits siting of offshore renewable facilities, it is unclear whether the overall impact of the Act will be a boost to offshore renewable development. The law creates a 17-member ocean advisory committee, including an expert on renewable energy, to provide advice to the energy and environmental affairs secretariat.
	Federal	• In December, 2007, FERC began offering a faster Preliminary Permit process which will help the demonstration phase of the technology by authorizing ocean energy pilot projects for up to 5 years from the date of the license. Originally an approximately year-long process, the revised permitting will take as few as 6 months.

The FERC pilot process allows developers and regulators to get a better understanding of wave & tidal energy technologies and their impact by encouraging demonstration projects.

Demonstration-phase wave energy now costs about $7,000/kW. It is expected that commercial technology costs will be much lower.

	Wave Energy Economic and Performance Assumptions for Given Year of Installation (2008$)		
	2008[1] market/supported/acc	**2012[1] market/supported/acc**	**2020[1] market/supported/acc**
Plant Capacity (MW)[1]	5/5/5	5/5/5	25/25/25
Project Life (yrs)	20/20/20	20/20/20	20/20/20
Total Installed Cost ($/kW)	$7,000/$7,000/$7,000	$7,000/$7,000/$7,000	$2,300/$2,500/$2,300
Fixed O&M ($/kW-yr)[2]	$30/$30/$30	$30/$30/$30	$22/$26/$22
Non-fuel variable O&M ($/MWh)[2]	$25/$25/$25	$25/$25/$25	$21/$23/$21
Net Capacity Factor (%)[3]	15%/15%/15%	15%/15%/15%	38%/38%/38%

Sources: NCI Estimates 2008. System Level Design, Performance, and Costs – Oregon State Offshore Wave Power Plant – EPRI 2004. Proceedings of the Hydrokinetic and Wave Energy Technologies Technical and Environmental Issues Workshop, Washington, D.C., October 26-28, 2005, Prepared by RESOLVE, Inc., Washington, D.C. Susan Savitt Schwartz, ed. March 2006.; "Future Marine Energy", Carbon Trust, January 2006; NCI interviews with industry representatives.

1. Costs and plant capacity in 2008 and 2012 assume pilot plants. 2020 costs assume commercial-scale plant.
2. O&M costs are very difficult to estimate and even more uncertain than capital costs. As a rule of thumb, some industry representatives suggested that total O&M costs would probably exceed that of wind by about 2 to 3 times.
3. Capacity factors will vary with site conditions.

Note: EPRI provides cost estimates that are several years old and so NCI therefore inflated them to reflect increased steel prices. The costs of the pilot plants has been estimated by talking with industry representatives, analyzing news clips, and reviewing the EPRI study. Future cost reductions should experience a learning curve cost reduction of about 10% to 20% each time production doubles.

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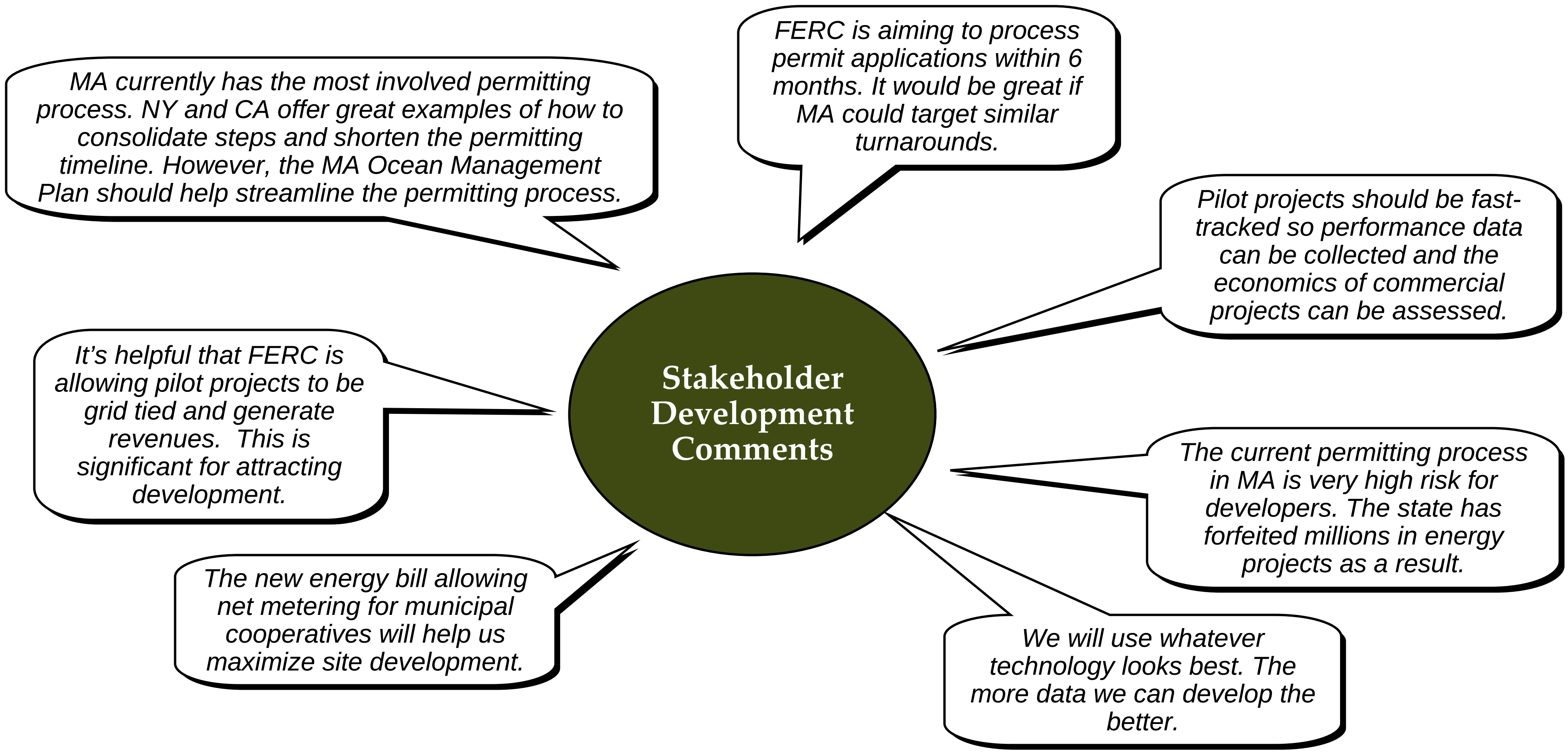
The installed cost of tidal power is now about $6,000/kW for demonstrations, it is expected that costs will decrease significantly as commercial-scale projects are built.

	Tidal Energy Economic and Performance Assumptions for Given Year of Installation (2008$)		
	2008[1] market/supported/acc	2012[1] market/supported/acc	2020[1] market/supported/acc
Plant Capacity (MW)[1]	1/1/1	5/5/5	10/10/10
Project Life (yrs)[2]	20/20/20	20/20/20	20/20/20
Total Installed Cost ($/kW)[3]	$6,000/$6,000/$6,000	$3,840/$3,920/$3,840	$3,200/$3,600/$3,200
Fixed O&M ($/kW-yr)[4]	$90/$90/$90	$90/$90/$90	$90/$90/$90
Net Capacity Factor (%)[5]	37%/37%/37%	37%/37%/37%	37%/37%/37%

Sources: NCI Estimates 2008. "Survey and Characterization, Tidal In Stream Energy Conversion (TISEC) Devises", EPRI, November 9, 2005; " North American Tidal In-Stream Energy Conversion (TISEC) Technology Feasibility Study" EPRI, June 11, 2006.; "System Level Design, Performance, Cost and Economic Assessment -MA Muskeget Channel Tidal In-Steam Power Plant" EPRI, 2006.; Report" Proceedings of the Hydrokinetic and Wave Energy Technologies Technical and Environmental Issues Workshop, Washington, D.C., October 26-28, 2005, Prepared by RESOLVE, Inc., Washington, D.C. Susan Savitt Schwartz, ed. March 2006.; "Future Marine Energy", Carbon Trust, January 2006; NCI interviews with industry representatives.

1. Costs and plant capacity in 2008 assumes pilot plants. 2012 and 2020 costs assume commercial-scale plant.
2. Project life is based on EPRI MA Tidal In-Steam Power Plant Report.
3. 2008 installed costs are based on EPRI MA Tidal In-Steam Power Plant Report.
4. Based on EPRI MA Tidal In-Steam Power Plant Report, the fixed O&M cost is about $77/kW-yr, which is slightly lower than the rule of thumb used by some industry representatives that total O&M costs would probably exceed that of wind by about 2 to 3 times. Therefore, $90/kW-yr is assumed here.
5. NCI assumed mid-level power density of 1.5 - 3 kW/m^2 which equals an approximate 40% capacity factor, based on EPRI TISEC Technology Feasibility Study, and decreased this average to better reflect locally estimated capacity factors for Muskeget, Vineyard Sound, and Cape Cod Canal.

Simplifying the permitting process is critical for developing Massachusetts ocean and other renewable resources.



Unproven technology is a barrier to commercial-scale tidal energy development. Pilots are critical and should be fast-tracked.

A number of barriers also exist that slow or prevent development of wave and tidal power.

Technical	• Tidal: Still in design/piloting stages, this power source is still undergoing technology optimization. No clear technology leader exists. Performance, equipment life, and O&M requirements have yet to be proven. • Wave: EPRI estimates of wave technology potential for MA are based on Ocean Power Delivery (OPD) Pelamis unit. Performance data were provided by the manufacturer based on a single test unit in Scotland. No clear technology leader exists. Performance, equipment life, and O&M requirements have yet to be proven.
Economic	• Technologies for tidal and waver energy are in the pilot or early demonstration commercialization stages. This makes cost estimates of commercial-scale development uncertain. • With no, or very limited, pilot project data, the economics remain uncertain, increasing the risk associated with project development. • Many developers currently rely on EPRI COE algorithms, which suggest a COE of 6-11 ¢/kWh.
Policy	• MA Ocean Management Plan will not be in place until December 2009, which may delay permitting for pilot projects. However, once in place should help to streamline the state permitting process.
Social	• Tidal: projects have limited social barriers as there is broad public support for renewables and no aesthetic issue since technology is submerged. • Wave: Aesthetics and interference with recreational boating could be a barrier for any large-scale wave project.

In performing our analyses, NCI reviewed a number of reports and interviewed a number of ocean energy industry participants.

- Studies and reports reviewed:
  - *Existing and Potential Ocean-Based Energy Facilities and Associated Infrastructure in Massachusetts*, TRC Environmental Corporation for MA Office of CZM, June 26, 2006
  - *North America Tidal In-Stream Energy Conversion Technology Feasibility Study*, EPRI, June 2006
  - *Massachusetts Tidal In-Stream Energy Conversion (TISEC) Survey and Characterization of Potential Project Sites*, EPRI, October 2006
  - *System Level Design, Performance, Cost and Economic Assessment -- Massachusetts Muskeget Channel Tidal In-Stream Power Plant*, EPRI, June 2006
  - *System Level Design, Performance, and Costs--Massachusetts State Offshore Wave Power Plant*, EPRI, Global Energy Partners, E2I, November 2004
  - *Offshore Wave Power Feasibility Demonstration Project*, Final Summary Report, EPRI, September 2005
  - *Instream Tidal Power Plant Feasibility Study, General Environmental and Federal Permitting Issues*, Devine Tarbell & Associates, Inc., presentation on May 9, 2006 by Andre Casavant.

- Ocean energy industry participants interviewed:
  - A number of project developers who wish to remain anonymous.
  - A local community energy consultant who wishes to remain anonymous.

- Massachusetts policy stakeholders interviewed:
  - Deerin Babb-Brott, Assistant Secretary for Oceans and Coastal Zone Management

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http://www.mass.gov/doer/