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Analysis of the Impact of Cape Wind on New England Energy Prices

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1. Summary

Charles River Associates (CRA) has conducted an analysis of the impact of the Cape Wind project on the ISO New England wholesale electricity market. Cape Wind, a 468 MW offshore wind power project planned for Nantucket Sound, is expected to provide enough power to supply approximately 10 percent of projected 2013 demand in Southeastern Massachusetts and just over 1 percent of total projected 2013 New England demand. This additional supply will reduce the need for generation from other power plants with higher pollutant emissions and operating costs, primarily fueled by natural gas, oil, and coal. CRA has projected wholesale power prices over the period 2013-2037, for scenarios with and without Cape Wind in service, and quantified the expected reduction in wholesale power prices and wholesale electricity costs that would result from the power supplied by the project.

The principal findings of the analysis are:

- **Adding Cape Wind would lead to a reduction in the wholesale cost of power averaging $185 million annually over the 2013-2037 time period, resulting in an aggregate savings of $4.6 billion over 25 years.**
- **With Cape Wind in service, over the 2013-2037 time period, the price of power in the New England wholesale market would be $1.22/MWh lower on average.**

2. Approach

In New England, electric power is bought and sold through a competitive wholesale market.[1] As a result of industry restructuring, New England utilities and other load serving entities own and operate almost no generating capacity, but rather make wholesale purchases from the competitive market, the costs of which are ultimately recovered through retail rates charged to end-use customers. Most New England customers pay a retail rate closely tied to prices set in periodic Standard Offer Service auctions, which in turn closely ties to expected wholesale power costs. Wholesale power costs are therefore a good measure of electricity costs for consumers in the New England Region. CRA has estimated the savings from Cape Wind by comparing wholesale power costs for the region with and without the project in service.

Introducing Cape Wind's additional supply into the competitive wholesale power market will lower prices by displacing higher cost generation. Power in New England is priced hourly,

[1] Power can be purchased through spot markets administered by ISO New England, or though bilateral transactions and forward electricity markets. The power sold from Cape Wind will affect prices in all of these markets, regardless of whether the output is sold under contract or through the spot markets. In fact, all generation, even if under contract, must be scheduled through the ISO New England spot markets. Power that is under contract for physical delivery is simply included at the bottom of the supply stack, therefore directly affecting the spot market. Likewise, expectations about prices in the spot market drive the pricing for forward transactions.

with the market price set by the offer from the highest-cost source of supply needed to meet demand. In each hour that the price is set by power plants with lower operating costs, rather than higher-cost units displaced by the supply from Cape Wind, the wholesale clearing price will be lower and electricity costs reduced. The variable operating cost of wind turbine generators is almost zero, so electricity from Cape Wind will be offered at the bottom of the regional supply stack in every hour it is available. Hence, Cape Wind will displace higher-cost generation and the associated greenhouse gas emissions in almost every hour of every year, resulting in a reduction in the market price. CRA has estimated these price decreases for each hour of each year from 2013 through 2037 and calculated the associated reduction in wholesale power costs.

The projections provided in this report cover the 2013 through 2037 time period and rely on the following key input assumptions:

- Natural gas and oil prices are based on the Energy Information Administration (EIA)[2] Annual Energy Outlook (AEO) 2009, as updated in April 2009 to account for the change in economic conditions in the prior six months.
- Federal greenhouse gas program in place with prices of $30/ton of carbon dioxide in 2013, escalating by 2030 to $60/ton, scenarios that are consistent with those presented in ExxonMobil's Outlook for Energy, A View to 2030.
- Electricity demand growth as projected by ISO New England in its most recent forecast, released in April of 2009.
- Inflation of 2.01 percent annually, based on the assumptions in the AEO 2009.

Additional detail about these assumptions is included in an appendix to this report.

CRA used the GE MAPS electricity market model to develop a fundamental forecast of market prices and generator dispatch for the New England Market. The GE MAPS model is a security-constrained dispatch model that simulates the chronological, hourly operation of an electricity market. The model takes the specified, cost-based bids for each generator in the market, along with other generating unit operating assumptions and performs a least-cost dispatch subject to limits on the flow of power across power lines and other elements of the transmission system. The model finds the least-cost dispatch of power plants and calculates hourly prices for electricity for each location within the New England market using the same basic approach that is applied in the actual operation of the power system and wholesale market.

CRA's analysis relied on forecasted production patterns that Cape Wind provided for the project. The production profile includes, for each month of the year, an average value for each hour of the day. In reality, there will be day-to-day fluctuations not captured in these patterns. Test data for the project site indicate that the hourly fluctuations during the summer

[2] EIA, an administration with the US Department of Energy, provides data and forecast for the energy sector. The AEO provides a comprehensive, long-term view on energy supply, demand, and prices, based on fundamental modeling of the markets for each energy commodity. The 2009 AEO is available at: http://www.eia.doe.gov/oiaf/archive/aeo09/index.html

months are coincident with warmer weather and higher electric demand. For example, due to the summer sea breeze effect, above average wind speeds have been recorded by Cape Wind's Scientific Data Tower on Horseshoe Shoal during eleven of the past twelve peak electric demand events in New England. Hence, CRA's estimates are likely to understate the potential benefits during summer peak hours.

3. Results

3.1. Wholesale Price Impact

Figure 2 shows CRA's estimates of difference in the average New England wholesale power prices with and without Cape Wind in service. Over the 25 years covered by the analysis, prices would be an average of $1.22/MWh lower with the project than without. As shown in Figure 3, the effect on wholesale electricity prices is even more pronounced for Southeastern Massachusetts, where the project will be interconnected with the New England grid. The average price reduction for that zone is $1.82/MWh.

Figure 1: Wholesale Price Reduction for New England

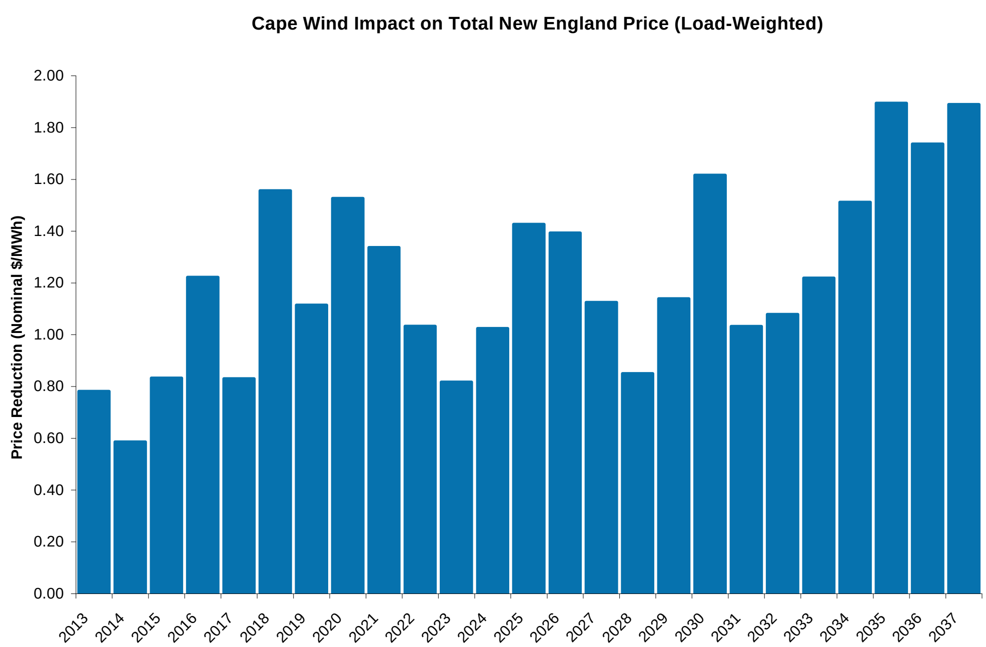
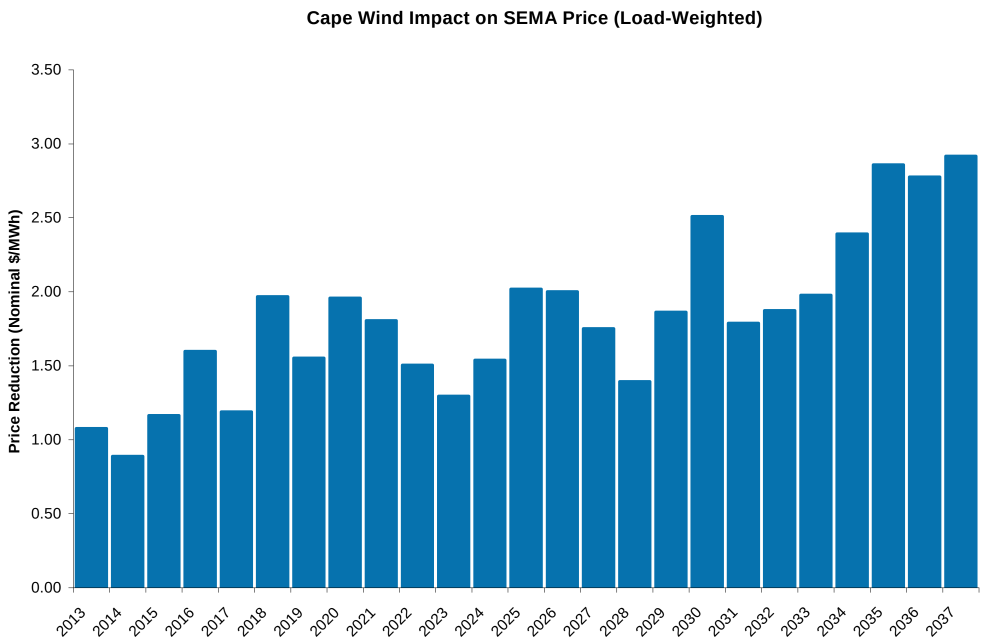


Figure 2: Wholesale Price Reduction for Southeastern Massachusetts

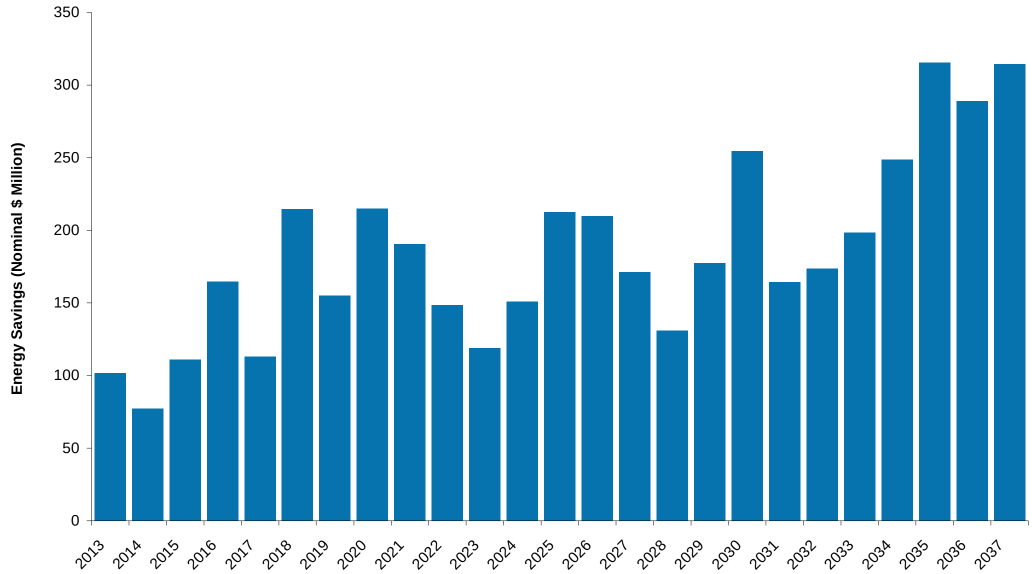


3.2. ESTIMATED SAVINGS IN ELECTRICITY COSTS

Figure 4 shows the expected savings in electricity costs associated with the forecasted reduction in wholesale market prices. The cost savings range between $77 million and $315 million annually, totaling $4.6 billion over the 25 year period. The savings fluctuate from year-to-year due primarily to the addition of new generating capacity added to meet regional demand growth. Because minimum efficient scale for new power plants is generally large, on the order of 500 MW, adding a new plant creates an initial surplus, which depresses the electricity price, and prices then rise as the surplus is absorbed by demand growth.[3]

[3] Additionally, the price impact and cost savings fluctuate from year-to-year based on the timing of forced outages for generating units, which are assigned randomly within CRA's model.

Figure 3: Projected Reduction in Wholesale Power Costs with Cape Wind in Service



3.3. CHANGE IN NEW ENGLAND GENERATION MIX

In order to illustrate how the Cape Wind project would change the generation mix for New England, Figure 5 shows the change in generation for non-wind resources for a representative year, 2015. As shown in Table 1, the expected pattern is very similar for other years. The output of Cape Wind will displace other generation from fossil fueled power plants, burning primarily gas, oil, and coal. Additionally, the pumped storage hydro facilities in New England would be utilized slightly more with Cape Wind in service, allowing some of the off-peak wind generation to be stored and used during peak periods. A small portion of the additional power from Cape Wind also displaces imports, or contributes to exports, for a reduction in total net imports to New England.

Figure 4: Change in Other New England Generation with Cape Wind in Service, 2015

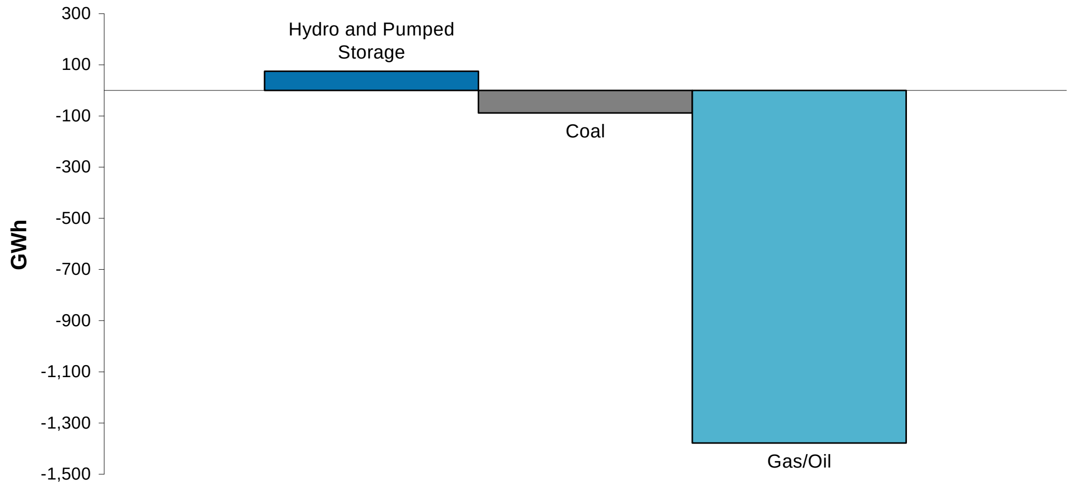


Table 1: Change in Non-Wind Generation by Fuel Type (GWh)

	2015	2020	2025	2030
Coal	(61)	(34)	(39)	(19)
Gas/Oil	(1,145)	(1,187)	(1,133)	(1,264)
Hydro	39	30	30	16
Demand Response	1	(4)	(5)	(10)

APPENDIX: KEY ASSUMPTIONS

A.1 FORECASTED DEMAND

- Demand and peak loads for 2013-2018 are based on the 2009 ISO-NE CELT report, the most recent regional forecast for New England.
- Beyond 2018, CRA escalated loads at the compound average growth rate for the 2013-2018 period (1.06%).
- ISO-NE projects hourly electricity demand by zone through 2018; these hourly demand forecasts were used in CRA's model runs, with the 2018 pattern used for all years thereafter, scaled appropriately to reflect demand growth.

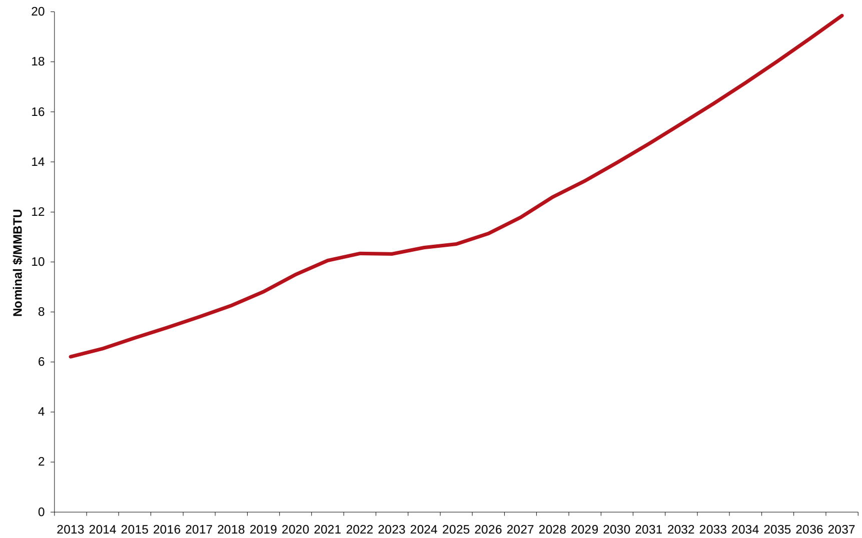
Table 2: Load Forecast

Year	2009 CELT Energy (GWh)	2009 CELT Peak (MW)
2009	131,315	27,875
2010	131,330	28,160
2011	132,350	28,575
2012	134,015	29,020
2013	134,635	29,365
2014	136,085	29,750
2015	137,540	30,115
2016	139,025	30,415
2017	140,565	30,695
2018	142,125	30,960
2019	143,672	31,289
2020	145,236	31,622
2021	146,818	31,958
2022	148,416	32,298
2023	150,032	32,642
2024	151,665	32,989
2025	153,316	33,340
2026	154,985	33,694
2027	156,673	34,052
2028	158,378	34,415
2029	160,102	34,781
2030	161,845	35,150
2031	163,607	35,524
2032	165,389	35,902
2033	167,189	36,284
2034	169,009	36,670
2035	170,849	37,060
2036	170,849	37,060
2037	170,849	37,060

A.2 FUEL PRICES AND CARBON POLICY

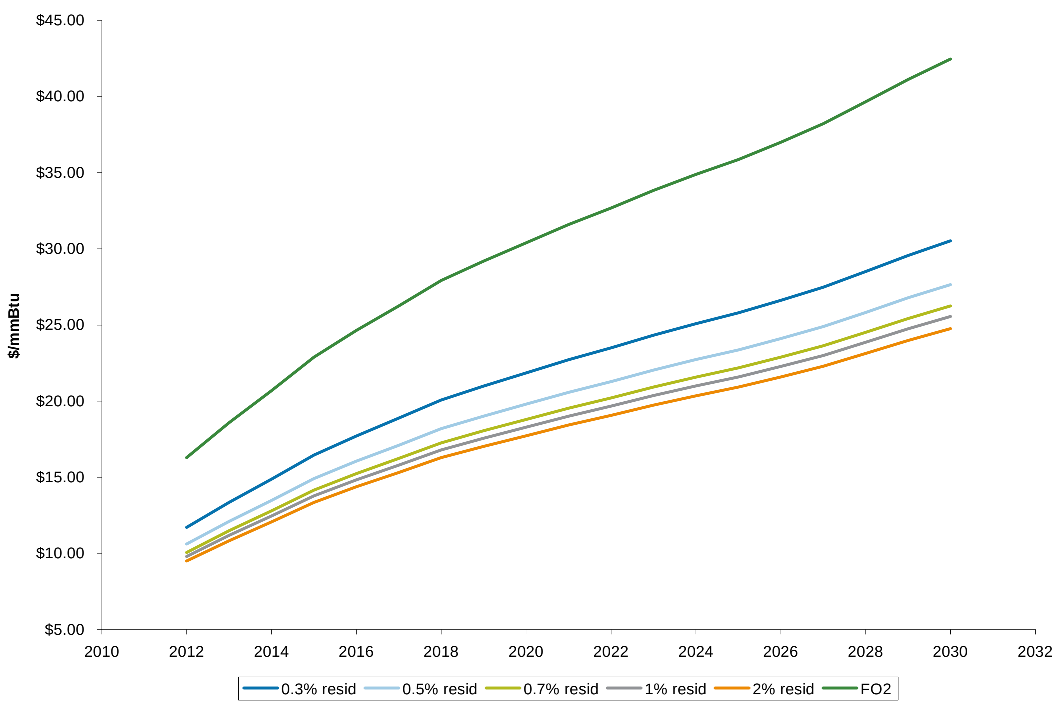
The gas forecast is based on the US EIA Annual Energy Outlook (AEO) 2009 forecast, released April 2009.

Figure 5: Henry Hub Natural Gas Prices (Nominal $/MMBtu)



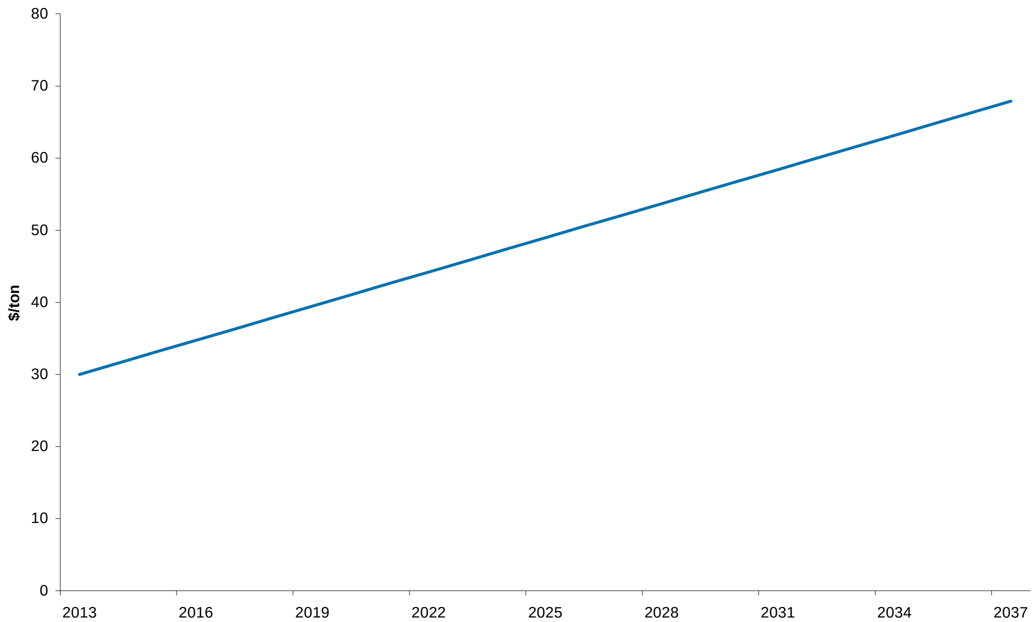
Oil prices are based on the April AEO2009 crude oil price forecast. CRA applied the most recent two-year Bloomberg historical relationships between crude and product prices to derive oil product prices from AEO2009 crude oil prices.

Figure 6: Oil Prices (Nominal $/MMBtu)



A federal carbon policy is assumed to be in place, resulting in costs of $30/ton in 2013 and escalating to $60/ton by 2030, consistent with scenarios presented in ExxonMobil's Outlook for Energy – A View to 2030. Beyond 2030, costs were assumed to escalate at the same average annual increase applied for the 2013 to 2030 period.

Figure 7: CO_2 Allowance Prices



A.3 INFLATION ASSUMPTIONS

All values in this report are in nominal dollars, assuming an average inflation rate of 2.01 percent. The assumption is based on the inflation rates applied in the AEO 2009, shown in Table 3.

Table 3: Inflation Rates

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
GDP Chain-type Price Index (2000=1.000)	1.237	1.243	1.258	1.274	1.297	1.324	1.354	1.385	1.417	1.450	1.484
Annual inflation rate	0.99%	0.55%	1.18%	1.25%	1.79%	2.12%	2.23%	2.29%	2.30%	2.37%	2.38%

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
GDP Chain-type Price Index (2000=1.000)	1.521	1.560	1.600	1.638	1.675	1.711	1.746	1.782	1.820	1.858	1.896
Annual inflation rate	2.49%	2.55%	2.54%	2.39%	2.26%	2.12%	2.08%	2.07%	2.11%	2.08%	2.07%