2013 Offer Review Trigger Prices Study

PREPARED FOR

ISO new england

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This report was prepared for ISO New England. All results and any errors are the responsibility of the authors and do not represent the opinion of The Brattle Group, Inc. or its clients.

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Executive Summary

ISO New England retained The Brattle Group and Sargent & Lundy to develop Offer Review Trigger Prices (ORTPs) for use in administering the Minimum Offer Price Rule in the Forward Capacity Market. This ORTP Study report explains the stakeholder input process, the bottom-up analysis of costs and revenues, and the key assumptions used to develop the ORTPs.

Table 1 summarizes the cost and revenues estimates and resulting ORTP values for each resource type. These values apply to the ninth Forward Capacity Auction (FCA9) for the 2018/19 delivery period.

Table 1
Recommended ORTP Values for FCA9

Resource Type	Total Plant Capital Cost *($m)*	Installed Capacity *(MW)*	Qualified Capacity *(MW)*	Overnight Cost *($/kW)*	After-Tax WACC *(%)*	Fixed O&M *($/kW-mo)*	Gross CONE *($/kW-mo)*	Revenue Offsets *($/kW-mo)*	Net CONE *($/kW-mo)*	FCA 9 ORTP *($/kW-mo)*
Combustion Turbine	$318	192	192	$1,583	7.2%	$2.65	$16.13	$2.71	$13.42	**$13.424**
Combined Cycle	$878	730	730	$1,108	7.2%	$2.33	$12.61	$3.75	$8.87	**$8.866**
Onshore Wind	$196	60	15	$3,063	7.2%	$6.62	$23.89	$27.53	-$3.64	**$0.000**
Energy Efficiency	n.a.	1.0	1.0	$2,571	7.2%	$0.00	$24.39	$25.37	-$0.97	**$0.000**
Large DR	n.a.	0.5	0.5	n.a.	7.2%	n.a.	$1.15	$0.00	$1.15	**$1.145**
Mass Market DR	n.a.	0.001	0.001	n.a.	7.2%	n.a.	$7.09	$0.00	$7.09	**$7.094**

The ORTPs shown in Table 1 also provide a basis for establishing ORTPs for FCA10 and FCA11, through indexing. Table 2 summarizes the recommended indices for escalating cost components; Revenues would be adjusted using updated futures prices for electricity (Mass Hub On-Peak) and natural gas (Henry Hub and Algonquin City-Gates) in New England.

Table 2
Recommended Indices for Future ORTP Updates

Cost Component	Index
Capital Costs	
Gas Turbines	BLS-PPI "Turbines and Turbine Generator Sets"
Steam Turbines	BLS-PPI "Turbines and Turbine Generator Sets"
Wind Turbines	Bloomberg Wind Turbine Price Index
Other Equipment	BLS-PPI "General Purpose Machinery and Equipment"
Construction Labor	BLS "Quarterly Census of Employment and Wages" 2371 Utility System Construction Average Annual Pay: - Combustion Turbine and Combined Cycle Gas Turbine costs to be indexed to values corresponding to the location of Hampden County, Massachusetts - On-shore Wind costs to be indexed to values corresponding to the location of Cumberland County, Maine
Other Labor	BLS "Quarterly Census of Employment and Wages" 2211 Power Generation and Supply Average Annual Pay: - Combustion Turbine and Combined Cycle Gas Turbine costs to be indexed to values corresponding to the location of Hampden County, Massachusetts - On-shore Wind costs to be indexed to values corresponding to the location of Cumberland County, Maine
Materials	BLS-PPI "Materials and Components for Construction"
Electric Interconnection	BLS-PPI "Electric Power Transmission, Control, and Distribution"
Gas Interconnection	BLS-PPI "Natural Gas Distribution: Delivered to ultimate consumers for the account of others (transportation only)"
Fuel Inventories	Federal Reserve Bank of St. Louis "Gross Domestic Product: Implicit Price Deflator (GDPDEF)"
Fixed O&M Costs	
Labor, Administrative and General	BLS "Quarterly Census of Employment and Wages" 2211 Power Generation and Supply Average Annual Pay: - Combustion Turbine and Combined Cycle Gas Turbine costs to be indexed to values corresponding to the location of Hampden County, Massachusetts - On-shore Wind costs to be indexed to values corresponding to the location of Cumberland County, Maine
Materials and Contract Services	BLS-PPI "Materials and Components for Construction"
Site Leasing Costs	Federal Reserve Bank of St. Louis "Gross Domestic Product: Implicit Price Deflator (GDPDEF)"

Note: "BLS-PPI" denotes the Bureau of Labor Statistics Producer Price Index.

I. Introduction

A. Background

ISO New England (ISO-NE) facilitates a market-based approach to meeting its resource adequacy objectives by administering a Forward Capacity Market (FCM). The FCM includes annual three-year Forward Capacity Auctions (FCAs) and subsequent reconfiguration auctions designed to clear sufficient resources for each one-year capability period. To date, seven FCAs have been conducted, for capability periods 2010/11 (FCA1) through 2016/17 (FCA7), as well as several reconfiguration auctions.

In the auctions, ISO-NE's Internal Market Monitor (IMM) monitors and may mitigate supply offers to support competitive market outcomes. The IMM has always guarded against supplier market power by disallowing existing resources from submitting "de-list" bids above competitive levels reflective of individual resource's costs.[1] To guard against downward price manipulation by buyers, the IMM has employed different approaches over time, starting with its Alternative Price Rule (APR) in the original FCM design. The APR was ultimately deemed "unjust and unreasonable" by the Federal Energy Regulatory Commission (FERC), which directed ISO-NE to work with stakeholders to develop an alternative similar to PJM Interconnection's Minimum Offer Price Rule (MOPR).[2] ISO-NE filed its own MOPR,[3] which went into effect starting with FCA8 for the 2017/18 capability period.

ISO-NE's MOPR works by subjecting all new entrants to a minimum offer price. The IMM does so by comparing each offer to a competitive benchmark, the Offer Review Trigger Price (ORTP) defined in the tariff for that resource type. If the offer is below the ORTP for that resource type, the IMM reviews the basis for the offer and determines whether and how much to mitigate the offer upwards. Resource types that do not have an ORTP defined in the tariff are reviewed if their offers are below the auction starting price.[4] ORTPs are currently in effect for several resource types for the 2017/18 capability period, since they were established in FERC's February 2013 Order.[5]

B. Study Objectives, Scope, and Approach

ISO-NE's tariff requires re-calculation of ORTP values no less than once every three years using updated data.[6] The IMM opted to conduct this 2013 ORTP Study earlier than required, consistent with its statement in its December, 3, 2012 Compliance filing that it "will consider whether the Offer Review Trigger Prices should be recalculated using updated data sooner than would be required under the Tariff Changes, possibly for the ninth FCA."[7]

The objective of the 2013 ORTP Study is to develop updated benchmark values for new capacity resources in FCA9. The IMM provided guidance to the study authors and stakeholders on how to develop ORTPs so that they would be consistent with the ISO-NE tariff and FERC orders: ORTPs should represent the low end of competitive offers. This objective is consistent with

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1 ISO-NE, 2013. Section III.13.1.2.3.2.1.1, Internal Market Monitor Review of De-List Bids

2 FERC, 2011.

3 ISO-NE and PTO, 2012.

4 ISO-NE, 2013. Section III.A.21.1, Offer Review Trigger Prices

5 FERC, 2013. Previously established ORTP values were $10.00/kW-month for Combustion Turbine, $11.00/kW-month for Combined Cycle Gas Turbine, $24.00/kW-month for Biomass, $14.00/kW-month for On-Shore Wind, $1.00/kW-month for Real-Time Demand Response, $0.00/kW-month for Energy Efficiency.

6 ISO-NE, 2013. Section III.A.21.1.2 Calculation of Offer Review Trigger Prices.

7 ISO-NE and PTO, 2012.

FERC's statements in its 2013 order that only bids that appear "commercially implausible absent out-of-market revenues" would be below the ORTP threshold and thus subjected to IMM review.[8]

Accordingly, this study presents ORTPs developed through a bottom-up analysis of costs and revenues. It includes ORTPs for several resource types—combined-cycle gas turbines (CCGTs), combustion turbines (CTs), onshore wind, demand response (DR), and energy efficiency (EE). Each resource type has technical specifications reflecting what a competitive entrant is likely to bring to market. We assume plausibly favorable site conditions and the presence of a power purchase agreement (PPA) for non-capacity revenues, consistent with the tariff and FERC guidance. As requested by FERC, the ORTPs for demand-response resources are based on a broader review of cost data than the values calculated for FCA8.[9] This study also provides indices for escalating the costs and revenues so that the IMM can formulaically update ORTP values for use in FCA10 and FCA11.

ISO-NE and The Brattle Group solicited input from ISO-NE stakeholders throughout this study through presentations to the New England Power Pool Markets Committee on the study approach (June meeting), updated approach (July), draft results (August), and final results (September). Stakeholders provided comments at those meetings and in subsequent correspondence, all of which the study authors reviewed. Their input is included in the recommended ORTPs and/or addressed in this report.

This report provides a summary of the methodology, inputs and assumptions, and recommended ORTP values for each resource. In addition to this report, the calculations of the ORTP values have been included in the ISO-NE 2013 ORTP Study Capital Budgeting Model spreadsheet, which is available on the ISO-NE website.[10]

II. Methodology

Our methodology starts with the selection of resource types and their technical specifications, followed by the estimation of capital and fixed operations and maintenance (O&M) costs for each type. Together, the capital and fixed O&M costs determine the amount of net revenue the

8 FERC, 2013. "[We] are satisfied by ISO-NE's rationalization that, in the case of New England, use of trigger prices at the low end of the spectrum strikes a reasonable balance by not subjecting clearly competitive offers to IMM evaluation, but only addressing those offers that plainly appear commercially implausible absent out-of-market revenues."

9 FERC, 2013. "[We] strongly encourage ISO-NE, during the next complete update of trigger prices, to revise its demand response trigger price methodology so that it does not rely on such limited data."

10 See http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/oct892013/a06_iso_ortp_analysis_final_results_10_02_13.xlsx

resource must earn over its lifetime. Of particular interest to developing an ORTP is the amount the resource must earn in just its first year of operation to achieve the necessary return on, and of, capital, given a long-term view of future revenue projections. This first year revenue that yields a net present value (NPV) of zero for the project is called the "Cost of New Entry" (CONE).

The projects rely on both capacity and non-capacity revenues to earn its CONE. Non-capacity revenues may include energy, ancillary services, and Renewable Energy Credits (RECs), where applicable. We estimate these non-capacity revenues then subtract them from the CONE to calculate the revenue required solely from the FCM in order to be competitively viable. The result is called the "Net Cost of New Entry" (Net CONE).

Finally, the ORTP values are set at the Net CONE for each resource per kilowatt of qualified capacity per month.[11]

A. Selection of Resource Types for Developing ORTPs

1. Resource Types for Which an ORTP Is Proposed

ORTP values are proposed for new entrants of the following types:

- Combustion Turbine
- Combined Cycle Gas Turbine
- Onshore Wind
- Energy Efficiency
- Large Demand Response (Large DR)
- Mass Market Demand Response (Mass Market DR)

This selection was based on ISO-NE's specifications and stakeholder input of resource types that are (1) likely to offer into the FCM, (2) have reasonably good cost information available, and (3) are expected to cost less than the auction starting price.

For each resource type, we sought to describe the technical specifications—technologies, plant configurations, and site characteristics—representative of a resource expected to make a competitive offer to the FCA, in accordance with FERC's guidance on the objective of the ORTP values.[12] The specifics for each resource type were informed by our analysis of the predominant practice among recently-developed resources. They were also informed by our analysis of the relevant technologies, regulations, and infrastructure, and by guidance from Sargent & Lundy. The resulting assumptions are described in Sections III through VII.

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[11] In the case where the Net CONE for a resource is determined to be a negative value, the ORTP value will be zero.

[12] See Background section above.

2. Resource Types for Which No Specific ORTP Was Calculated

We also assessed biomass, solar photovoltaics (PV) and offshore wind but did not calculate ORTPs for them. Biomass was considered because it was in the prior ORTP study; solar PV and offshore wind were considered because ISO-NE stakeholders specifically requested ORTPs for them. We did not develop ORTPs for any of these technologies because we did not have sufficient information and/or the cost of these resources appeared to be greater than the auction starting price. Thus, their ORTP would default to the FCA starting price, subjecting them to IMM review if they seek to enter at a lower price.

Biomass costs appear to be high enough not to warrant an ORTP below the auction starting price. Our analysis indicates that the cost of building and operating a new 50 MW biomass facility (with a 2018 commercial online date) exceeds $7,000 per kilowatt. As a result, ISO-NE's IMM concluded that the ORTP value for Biomass should be set at the auction starting price. If actual units are developed at lower cost, offers to the FCA below the starting price would be recognized in their unit-specific reviews.

Similarly, Solar PV costs appear to be high enough not to warrant an ORTP below the auction starting price. This conclusion is based on an analysis that recognized two unique features of this resource type: (1) many Solar PV investments are eligible for "out-of-market" Massachusetts Solar Renewable Energy Certifications (SREC) that substantially enhance project economics, though the tariff excludes such targeted subsidies from the ORTP calculation;[13] and (2) Solar PV capital costs have continued to decline rapidly over the past several years such that it is difficult to estimate capital costs for a 2018 online date.[14] We estimated current capital costs and projected them forward at a 6% annual real decline rate, which is on the optimistic end of historical cost trends.[15] Current capital cost estimates are based on installed cost for actual plants from Sargent

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13 ISO-NE, 2013. Section III.A.21.2 New Resource Offer Floor Prices . "The Internal Market Monitor will exclude any out-of-market revenue sources from the cash flows used to evaluate the requested offer price. Out-of-market revenues are any revenues that are: (a) not tradable throughout the New England Control Area or that are restricted to resources within a particular state or other geographic sub-region; or (b) not available to all resources of the same physical type within the New England Control Area, regardless of the resource owner."

14 The recent Lawrence Berkeley National Lab report *Tracking the Sun VI: The Installed Price of Photovoltaics in the United States from 1998 to 2012* reports that installed prices for systems >100 kW declined by 6% in 2012, while installed prices for systems <10 kW declined by 14%. (Barbose, *et al.*, 2013)

15 We reviewed several sources for projected trends in solar PV installed costs, which tend to be lower than the historical decline seen in the LBNL in the Tracking the Sun VI report (see previous note). The European Photovoltaic Industry Association has projected cost declines of 3 – 4% real decline per year for several scenarios. (EPIA, 2011) For the NREL Renewable Electricity Futures Study published in 2012, Black and Veatch provided a report on solar PV costs. For the 1 MW system, the cost trends show a 2% per year real decline through 2015 and a 1% per year real decline through 2020. (B&V, 2012)

and Lundy's proprietary data with commercial online dates from 2011 and later and with capacities (in megawatts) larger than what is expected to be built in New England in the near future.[16]

Resulting Solar PV installed costs estimates were $3,139/kW in 2013 (in 2013 dollars) and $2,593/kW in 2018 (in 2018 dollars).[17] At that cost, the ORTP would be above the auction starting price, given various other assumptions about tax benefits, fixed O&M costs, generation output, future energy, and REC (not SREC) prices. The 2013 capital costs would have to be less than $2,500/kW and the 2018 values less than $2,100 for the ORTP value to be less than the auction starting price, all else being equal. That would require a 30% reduction from our estimates. As a result of this analysis, ISO-NE's IMM concluded that the ORTP value for Solar PV should be set at the auction starting price. If actual units are developed at lower cost, offers to the FCA below the starting price would be recognized in their unit-specific reviews.

For offshore wind, there was insufficient data available to Brattle and S&L to develop an ORTP due to the limited experience with this technology in the U.S. We solicited data from stakeholders and, although they provided a range of data, the cost information was insufficiently detailed to inform a complete ORTP calculation using a consistent bottom-up analytical framework that was applied to technologies for which ORTPs were calculated. Thus, ISO-NE's IMM determined that no resource specific-ORTP value would be developed, and the ORTP value would be set at the starting price. Actual resources will be able to seek lower offer prices based on their specific costs and characteristics.

B. Development of Capital Cost Estimates

1. Generation Technologies

Capital costs are presented with generation "owner's costs" separated from engineering, procurement, and construction (EPC) costs incurred by EPC contractors. EPC costs include construction labor, other labor, materials, sales tax, EPC contractor fees, EPC contingency and the cost of major equipment, such as turbines, heat-recovery steam generators, and steam turbines, where applicable, since we have assumed that all major equipment is purchased by the EPC. "Owner's costs" include any additional costs normally incurred directly by the plant owner in the development and construction of the generation plant, such as development services, electrical and gas interconnection, fuel inventories, working capital, owner's contingency, and financing fees.

16 The solar plants that were included in our analysis have an average capacity (12 MW) that is higher than our specified capacity (6 MW).

17 The projected 2018 capital costs based on our analysis of current costs and expected trends in capital costs is $2,593/kW in 2018 dollars.

To develop estimates of capital costs for the generation technologies, we sub-contracted with Sargent & Lundy LLC (S&L). S&L is an engineering consulting firm with extensive experience in the evaluation and design of generation facilities, as well as in calculating inputs to CONE values for the NYISO capacity market. S&L developed capital and construction cost estimates using the data and models derived from their experience with actual projects. These data and models are also the same ones used by S&L to inform its CONE analysis for NYISO, but with different assumptions on plant configurations and locations.

In addition to the technical specifications developed for each new resource type, the following assumptions were made for developing capital costs representative of a competitive offer at the lower end of the spectrum, in accordance with the objective described in Section I.B:

- Electric, gas and water utilities, and transportation access nearby that do not require expensive connections, no new transmission line or pipeline is required for electrical and gas interconnection;

- An unencumbered site that allows an efficient general arrangement of the units and does not require remediation for legacy environmental issues;

- No pilings required for foundations; use spread footings;

- No emission reduction credits or other special environmental requirements necessary;

- Comparable or lower labor rates and comparable or higher labor productivity in comparison to most of ISO-NE; and

- A proficient developer with low contingency costs.

S&L estimated capital costs for a plant to be built in the current year at 2013 prices, reflecting the costs for a plant as if it were built overnight in 2013. These costs are thus referred to as the "overnight costs." The overnight costs do not include the cost of capital during construction. To translate these costs to a 2018 online date, we escalated each cost component by five years using escalation rates that S&L provided. The assumed annual escalation rates are 1.5% in real terms for labor costs and 0.4% for most non-labor costs. Backup fuel inventory costs are assumed to be falling at 1.1% per year in real terms, consistent with oil futures.

For estimating the "installed cost," which includes the cost of capital during construction, S&L provided capital drawdown schedules of the monthly cash flows incurred by the EPC and plant owner. The installed cost is the present value of the construction period cash flows as of the end of the construction period, where the discount rate is the cost of capital reflecting the risks of the project (see the "Cost of Capital" section below).

2. Demand-Side Resources

Demand-side resources include both energy efficiency and demand response. Energy efficiency capacity resources are most often bid into the FCA by a utility or other load serving entity as an aggregated "bundle" of state-mandated programs, not based on any single EE program. For this reason, we have chosen to collect resource size, annual energy savings, and program cost data on all of the state-mandated EE programs for calculating the EE ORTP value. We calculated a capital cost value of the overall New England EE bundle on a per-kilowatt basis based on the program cost data reported by each state for their programs, assuming all of the costs are incurred in the year prior to operation with no ongoing O&M costs. We include incentives and subsidies, as well as costs borne by the customers in the total program costs.

For demand response, there are a wide range of DR assets that bid into the ISO-NE capacity market. For determining ORTP values, we chose to separate the assets into two classes based on bids into the most recent FCA and defined a favorable customer for each asset class based on interviews with DR aggregators. The two assets classes are Large DR and Mass Market DR and are further defined in Section VII. We did not explicitly evaluate the CONE for DR resources backed by various types of distributed generation (e.g., CHP). The IMM determined that such resources will have an ORTP based on the underlying technology type, consistent with how the ORTPs assigned to DR resources backed by distributed generation today. Actual resources will be able to seek lower prices based on their costs and characteristics through the asset-specific review process.

We conducted interviews with demand response aggregators active in the New England market to understand the cost drivers and incremental costs of adding a new resource. A summary of questions and aggregators interviewed can be found in Appendix A. We have assumed that the customer is being added to an existing portfolio of DR resources such that only the incremental costs of bringing on the resource are considered in the analysis of costs.

The incremental cost components for establishing a new Large DR resource include only one-time capital costs, while Mass Market DR costs include both capital costs and annual costs of maintaining the program. In our calculation of ORTP for the DR assets, we have amortized the DR capital costs across the contract life of each asset type and added first year annual costs (such as customer incentives) to determine the cost of new entry.

We would ideally rely on Mass Market DR cost information from the state program filings. However, New England states do not have mature direct load control programs for mass market DR that we could use for our purposes. Therefore, we relied on information from one of the DR aggregators that specialize in direct load control (DLC) programs for mass market customers. We supplemented this information with cost info from Xcel Energy Saver's Switch program which is a very mature mass market DLC program.

C. DEVELOPMENT OF FIXED O&M COSTS

Fixed O&M costs have been defined as costs incurred every year after the generation plant enters commercial operation, including the ongoing labor, materials, and administrative costs, as well as costs associated with site leasing, property tax, and insurance. Similar to capital costs, S&L developed the estimates for the fixed O&M costs of the generation resources based on their experience with actual projects.

Although land costs are often included as a capital cost, current plant developers are likely to lease the land and include the costs in the fixed O&M costs. Leasing costs are estimated from recent listings for industrial real estate for the reference gas plants and rural land for the reference wind farm.

The following assumptions have been made in estimating the property tax and insurance costs included in the fixed O&M estimates. Property taxes are estimated from a sample of independent power projects in New England that have entered into agreements for payments in lieu of taxes (PILOT) with local jurisdictions. PILOT agreements are negotiated on a case-by-case basis and typically result in lower property taxes compared with the published commercial or industrial rates. Projects with PILOT agreements typically have rates between 0.25% to 1.00%, assuming a newer plant and no change in assessed valuation over the term of the agreement. Insurance costs are based on a sample of independent power projects recently under development in the Northeastern US and discussions with a project developer.

As with capital costs, all O&M costs were developed using current 2013 price estimates. We escalated O&M costs to 2018 costs assuming that land leasing costs would increase at inflation, labor cost would rise at 1.5% above inflation, and materials and administrative costs would rise at 0.4% above inflation. Annual inflation was assumed to be 2.25%, as explained in Section II.D.3. Finally, we assume that total fixed O&M costs escalate at the rate of inflation over the full twenty year economic life of the generation assets.

The results of capital and fixed O&M costs are presented in the description of each generation resource type, with detailed supporting documentation of S&L's analysis for the generation technologies in the Technical Appendix.

D. GROSS CONE CALCULATIONS

1. Approach

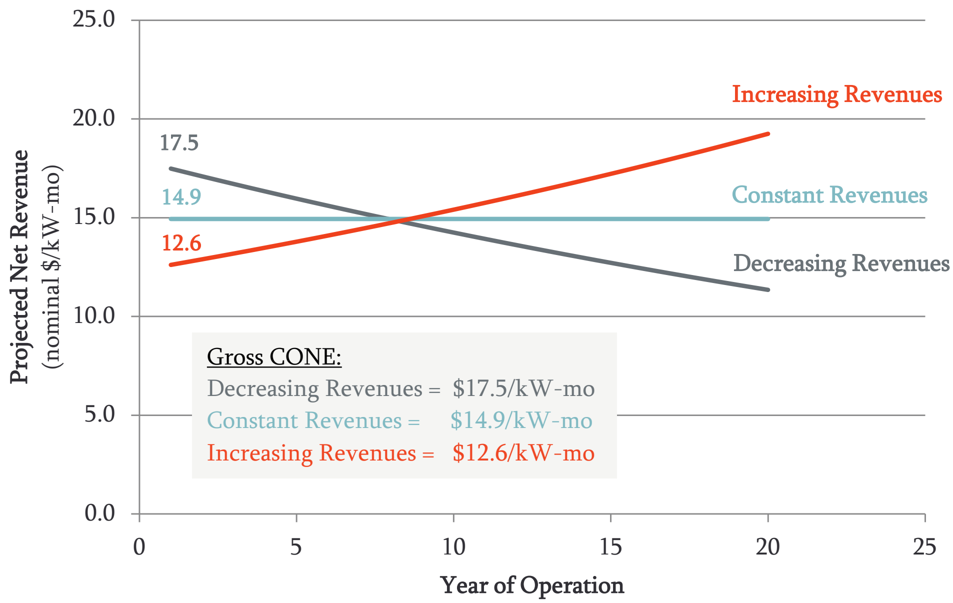
The CONE, sometimes called "Gross CONE" to distinguish from "Net CONE," is the net revenue a new resource would need in the first year of operation to be willing to enter the market.[18] It is

[18] Net revenue in this context refers to the revenues received net of variable costs of operation. Fixed costs are considered an additional cost elsewhere in the analysis.

the amount needed to achieve a zero NPV over the project's economic life, given reasonable assumptions about post-first-year revenues.

The two drivers of CONE are (1) estimates of the capital and other fixed costs to which an entry decision commits the resource owner (as described in the previous section above), and (2) projections of how total net revenues are likely to evolve over the long-term, or more specifically over the economic life of the resource. The impact of different projected net revenue escalation rates on CONE are shown in Figure 1 for the CCGT reference plant in the ORTP analysis.

Figure 1
Illustrative Impact of Projected Revenue Escalation Rates on (First-Year) Gross CONE[19]



If revenues are expected to be constant nominally over the long-term, cost recovery occurs in equal annual increments and results in a CONE of $14.9/kW-mo. However, if net revenues are projected to increase over time, lower first-year revenues are acceptable since more cost recovery will occur more in later years, as seen in the lower CONE value of $12.6/kW-mo. On the other hand, if net revenues are projected to decrease, higher first year revenues of $17.5/kW-mo are needed.

Long-term revenues depend on future prices for fuel, energy, capacity, ancillary services, and RECs, if applicable. We assume that future prices must be sufficient to support investment of future, competitive entrants. Thus, the two most significant factors affecting future prices are the

19 The three projected net revenues are of equal net present value equal to the present value of capital and fixed O&M costs for the reference CCGT plant in the ORTP study. Revenues are projected to increase/decrease nominally by 2.25% (the assumed inflation rate) only for demonstration purposes.

expected trends of future entrant capital costs and performance. These trends may vary by resource type.

For combustion turbines, capital costs have historically increased slightly faster than inflation, while performance and efficiency have consistently improved.[20] As these historical trends in the cost of capacity and performance have countervailing effects on total future revenues for a current entrant,[21] we have chosen to assume that the total revenues for gas plants will stay constant in real terms (*e.g.*, grow in nominal terms at the rate of inflation).

For wind turbines, capital costs have recently fallen, but it is not clear that they will continue to do so. Some of the recent reductions in cost appear to be due to temporary imbalances in the supply and demand for wind turbines which are not expected to continue over the long term. We have assumed that turbine costs will rise at a rate slightly faster than inflation while performance will continue to increase with the current trend of larger, more efficient turbines. With these countervailing factors on total revenues for a current entrant, we have chosen to assume that the total revenues for wind farms will stay constant in real terms, similar to our assumption for a gas-fired plant.

In our analysis, we have included the present value of the tax credits currently available to renewable resources—Production Tax Credit (PTC) or Investment Tax Credit (ITC)—in the CONE calculation. We assumed that the tax credits will continue to be available at their current respective rates through the FCA9 commitment period. For the onshore wind ORTP calculation, the PTC is estimated to be $25.7/MWh in 2018 dollars, based on current rules and the assumed inflation value.

2. Cost of Capital

An appropriate discount rate is needed to translate future cash flows into present values and to derive the CONE that makes the NPV zero. It is standard practice to discount future cash flows using an after-tax weighted-average cost of capital (ATWACC)[22] The appropriate ATWACC

[20] A detailed analysis of combustion turbine cost and performance trends is available in the 2011 PJM RPM Report Section IV.A.3. Pfeifenberger, *et al.*, 2011.

[21] For a current entrant, future revenues will be enhanced if *future* entrants' capital costs are increasing (all else equal), since prices will have to rise enough to attract them. However, this is not necessarily so if the future plants also are more efficient and able to out-compete current entrants in the energy market. Based on observed capital cost trends and performance trends referenced in the prior footnote, we assume that the net result is that current entrant future revenues will stay constant in real terms.

[22] The "after-tax weighted-average cost of capital" (ATWACC) is so-named because it accounts for both the cost of equity and the cost of debt, net of the tax deductibility of interest payments on debt, with the weights corresponding to the debt-equity ratio in the capital structure. Cash flows to which the ATWACC is applied must include revenues, costs, and taxes on income net of depreciation (but not

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reflects the risk of the project, which in this case lies primarily with the capacity market revenues since the tariff specifies a PPA for non-capacity revenues. It is a partially-hedged project with more risk than a regulated utility but less risk than a pure merchant generation project.

To estimate the cost of capital for such a project, we relied on market data for the two independent generation companies that are publicly traded: NRG and Calpine. Their costs of capital reflect their entire portfolios, which include primarily merchant facilities with some hedges in place. We assumed that the systemic risks of their portfolios are similar to the systemic (non-diversifiable) risks of our target plant in ISO-NE. We understand that NRG has more long-term contracts and hedges in place than Calpine, such that its lower portfolio risk may make its cost of capital more appropriate for our analysis which assumes a partial PPA. However, some stakeholders suggested that ISO-NE may be riskier than the average market in which the merchant generators' diversified portfolios operate, as the New England market has low load growth rate and is smaller in size, and its capacity market design is still in flux. Therefore, we decided to average the two companies' costs of capital, which are 6.9% for NRG and 7.6% for Calpine. The value-weighted average is 7.2%.

We derived ATWACC estimates for these companies using the following standard techniques.

- **Return on Equity**: We estimate the return on equity (ROE) using the Capital Asset Pricing Model (CAPM). The ROE for each company is derived as the risk-free rate plus a risk premium given by the expected risk premium of the overall market times the company's "beta."[23] We calculated a risk-free rate of 3.6% using a 15-day average of 30-year U.S. treasuries as of July 2013.[24] We estimated the expected risk premium of the market to be 6.5% based on the average of values provided by Credit Suisse and Ibbotson.[25] The "beta" describes each company stock's (five-year) historical correlation with the overall market, where the "market" is taken to be the S&P 500 index, which turned out to be 1.2 for both NRG and Calpine. The resulting return on equity is 11.4% for both companies.

- **Cost of Debt**: We estimate the cost of debt by compiling the unsecured senior credit ratings for each merchant generation company and examining the bond yields associated with those credit ratings. In Standard and Poor's (S&P) credit ratings, a company receives a higher rating based on its ability to meet financial commitments, with "AAA" being the

Continued from previous page

accounting for interest payments or their deductibility, since that is incorporated into the ATWACC itself).

23 See Brealey, *et al.*, 2011.

24 Bloomberg, 2013. Risk free rate calculated based on 30 year U.S. bond yields.

25 The Ibbotson market risk premium is 6.7% (Ibbotson, 2013) and the Credit Suisse market risk premium is 6.2% (Dimson, *et al.*, 2013)

highest rating and "D" being the lowest. Calpine's credit rating is "B," with an associated cost of debt of 8.7%, while NRG's is "BB" with a 7.6% cost of debt.[26]

- **Debt-Equity Ratio**: We estimate the five year average debt-equity ratio for each merchant generation company as reported in each company's annual 10-K report.

The results of the ATWACC analysis and the recommended ATWACC value for the ORTP calculations are shown in Table 3.

Table 3
After-tax Weighted Average Cost of Capital (ATWACC) Calculations

Company	Market Capitalization ($ Millions) [1]	S&P Credit Rating [2]	Equity Beta [3]	Return on Equity [4]	Cost of Debt [5]	Debt-to-Equity Ratio [6]	ATWACC [7]
Calpine Corp	9,594	B	1.22	11.4%	8.7%	63/37	7.6%
NRG Energy Inc	8,912	BB	1.21	11.4%	7.6%	67/33	6.9%
Merchant Generation Value-Weighted Portfolio			1.22	11.4%	8.2%	65/35	7.2%
Recommended Financial Parameters				**11.3%**	**5.2%**	**50/50**	**7.2%**

Sources and Notes:
[1] and [2]: Bloomberg as of July 23, 2013.
[3]: Calculated by The Brattle Group.
[4] = Assumed risk-free rate (3.59%) + assumed market risk premium (6.50%) x [3].
[5] and [6]: Bloomberg as of July 23, 2013.
[7] = [4] x [6] + (1 - assumed corporate income tax rate (40.5%) x (1 - [6]) x [5].

In the ORTP capital budgeting model, we assumed a capital structure of 50/50 debt-equity ratio. To maintain the ATWACC of 7.2% reflective of project risks (and independent of capital structure) we adjusted the cost of debt to 5.2% (the bond yield associated with a BBB credit rating) and the return on equity to 11.3%. As would be expected, the debt rate and equity rates are both lower for an assumed capital structure that is less leveraged than the sample companies.

We received feedback from a stakeholder (NRG) that the calculated cost of capital was too low due to non-systemic, project-specific risks not considered by the CAPM method, New England specific risks for merchant developers, and the low likelihood of a PPA. We disagree that non-systemic, project-specific risks, which tend to be idiosyncratic and non-market correlated, should be included in the cost of capital. Risk premia should be based solely on risks that are correlated with the overall market and are thus non-diversifiable.[27]

NRG also commented that the cost of capital should recognize that the New England market is riskier than Calpine and NRG's overall portfolios. We acknowledge their concern but also note

[26] Bloomberg, 2013. BBB bonds, which are not shown in the table but are used elsewhere in our analysis, are 5.2%.

[27] See Brealey, *et al.*, 2011.

that the tariff specifies the risk-mitigating assumption of a PPA on non-capacity revenues and that generators have the option of a five year lock-in of capacity revenues.[28] We also strived to avoid raising the cost of capital, and thus the ORTP, to a level that would deviate from FERC's guidance in its 2013 order that only bids that appear "commercially implausible absent out-of-market revenues" would be below the ORTP threshold. Considering all of these factors, we made a 30 basis-point upward adjustment from an original position of NRG's cost of capital to a final recommendation using the value-weighted average of the NRG and Calpine ATWACCs. Subsequent comments from NRG participants on the Markets Committee maintain that the discount rate is too low.

Other stakeholders asked how this methodology compares to that in the 2011 CONE study we conducted for PJM primarily for the purpose of setting the CONE parameter on its demand curve. In fact, the methodology is the same, but we have not included a forty basis point adder that we applied in PJM. That adder reflected a merchant assumption that differs from the partial PPA assumption required here, and it was needed to make the result consistent with available fairness opinions regarding merchant generation companies that had been sales candidates in PJM.[29]

3. Other Financial Assumptions

Calculating Gross CONE requires making several other financial assumptions about inflation rates, tax rates, and depreciation.

Inflation enters many aspects of the analysis, including estimates of future capital costs and the escalation rate of total net revenues. We estimated future twenty-year inflation rates based on bond market data, Federal Reserve estimates, and consensus U.S. economic projections. Table 4 shows that the implied inflation rate over twenty years from treasury yields is 2.2% and the Cleveland Federal Reserve estimate of inflation expectations is 1.9% over twenty years.[30] Figure 2 shows the historical nominal and inflation protected yields, implied inflation rate, and estimated inflation since 2010.

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28 ISO-NE, 2013. Section III.A.21.1.2(b). The ISO-NE tariff that states that cash flows should be "discounted at a rate consistent with that expected of a project whose output is under contract (i.e., a contract negotiated at arm's length between two unrelated parties)."

29 Spees, *et al.,* 2011.

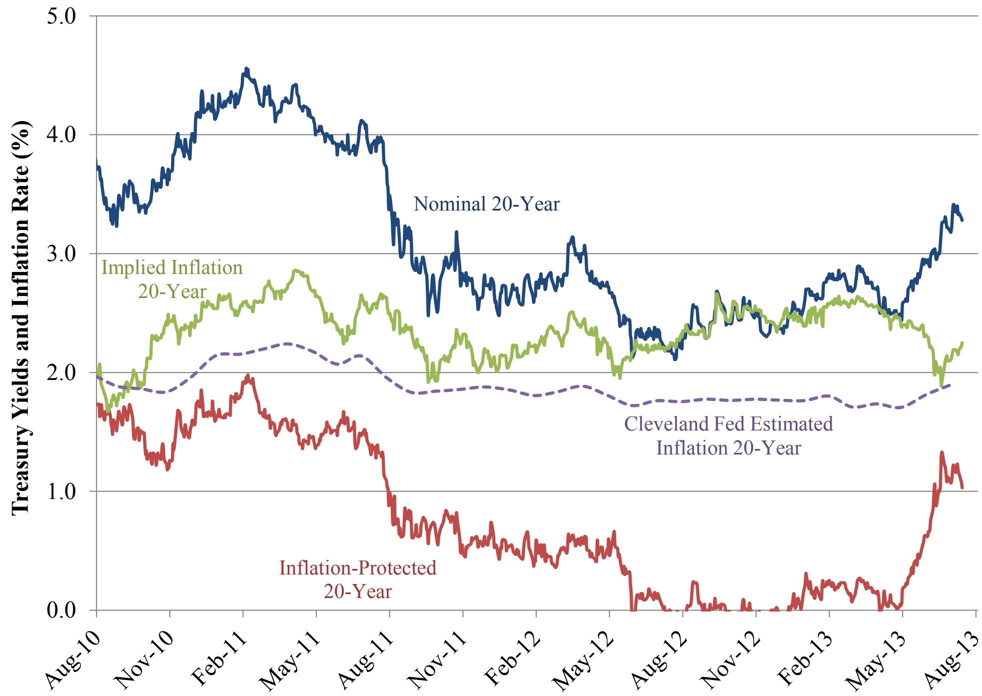
30 As stated on the Cleveland Federal Reserve website, "The Cleveland Fed's estimate of inflation expectations is based on a model that combines information from a number of sources to address the shortcomings of other, commonly used measures, such as the "break-even" rate derived from Treasury inflation protected securities (TIPS) or survey-based estimates. The Cleveland Fed model can produce estimates for many time horizons, and it isolates not only inflation expectations, but several other interesting variables, such as the real interest rate and the inflation risk premium. For more details, see the links in the box at right." Cleveland Fed, 2013.

Table 4
Federal Reserve Inflation Estimates

	10-year (%)	20-Year (%)	30-Year (%)
FRED Implied Inflation	**2.04**	**2.16**	**2.23**
FRED Nominal Yield	2.58	3.29	3.59
FRED Inflation Protected Yield	0.54	1.14	1.35
Cleveland Federal Reserve Estimated Inflation	**1.63**	**1.89**	**2.06**

Sources and Notes:
St. Louis Federal Reserve FRED 15-day average yields as of July 16, 2013.
Cleveland Federal Reserve monthly yields as of July 2013.

Figure 2
20 Year Inflation Estimates Since 2010



Source: St. Louis Fed, 2013 and Cleveland Fed, 2013.

The Blue Chip Economic Indicators report compiles analyst forecasts from various financial institutions and has consensus forecasts for various economic variables. The most forward looking forecast in the Blue Chip report is for the ten year time frame. The consensus ten-year average consumer price index (CPI) for all urban consumers is 2.3%.[31] Based on these sources, we assumed for the ORTP calculations an average long-term inflation rate of 2.25%.

31 Blue Chip Economic Indicators, 2013.

Income tax rates have been calculated based on current federal and state tax rates. The marginal federal tax rate for 2013 is 35%.[32] State-specific tax rates have been used for each reference technology based on the state in which it has been assumed to be located as shown in Table 5.

Table 5
State Corporate Income Tax Rates

State	Tax Rate *(%)*
Massachusetts	8.00%
Maine	8.93%

Sources: MA DOR, 2012 and Maine Revenue Services, 2012.

The federal tax code allows generating companies to use the Modified Accelerated Cost Recovery System (MACRS) of 20 years for a gas CC plant, 15 years for a gas CT plant, and 5 years for onshore wind. The depreciation schedules are shown in Table 6.

32 IRS, 2013a. The federal marginal income tax rate of 35% is applicable for all corporations with taxable income in excess of $18.3 million. Although some years in our analysis of onshore wind the taxable income is less than this value (and even negative in the early years due to accelerated depreciation), we assume that the facility is owned by a corporation with a taxable income that exceeds this threshold.

Table 6
MACRS Depreciation Schedule

Year	Combined Cycle Gas Turbine *20yr MACRS*	Combustion Turbine *15yr MACRS*	Onshore Wind *5yr MACRS*
1	6.563%	8.750%	35.000%
2	7.000%	9.130%	26.000%
3	6.482%	8.210%	15.600%
4	5.996%	7.390%	11.010%
5	5.546%	6.650%	11.010%
6	5.130%	5.990%	1.380%
7	4.746%	5.900%	
8	4.459%	5.910%	
9	4.459%	5.900%	
10	4.459%	5.910%	
11	4.459%	5.900%	
12	4.460%	5.910%	
13	4.459%	5.900%	
14	4.460%	5.910%	
15	4.459%	5.900%	
16	4.460%	0.740%	
17	4.459%		
18	4.460%		
19	4.459%		
20	4.460%		
21	0.565%		
Sum	**100.0%**	**100.0%**	**100.0%**

Source: IRS, 2013b.

To calculate the annual value of depreciation, the "depreciable costs" (which are different than the overnight and installed costs referred to earlier in the report) for a new resource is the sum of the overnight capital cost and the accumulated interest during construction (IDC). IDC is calculated based on the assumption that the construction capital structure is the same as the overall project, *i.e.*, 50% debt, and the cost of debt is the same.

E. Net CONE Calculations

As explained above, the Gross CONE is the total net revenue a new resource would need in the first year to be willing to enter the market. The total first year revenues received by a new resource can come from several sources depending on the resource, including capacity, energy and ancillary services, and RECs, if applicable.[33] ORTP values, however, reflect the amount of revenue required in the first year solely from the capacity market, which is known as the net cost of new entry, or "Net CONE." The Net CONE for each resource type is thus calculated by subtracting the first year non-capacity revenues from the Gross CONE, as shown in Equation 1.

[33] We have not included revenues or penalties that may in the future be derived from the ISO-NE Performance Incentives proposal currently being considered since the program design has not been finalized as of the time of our analysis.

$$\begin{aligned} Net\ CONE &= Gross\ CONE - First\ Year\ Non\ Capacity\ Revenue \\ &= First\ Year\ Capacity\ Revenue\ for\ NPV\ of\ 0 \end{aligned}$$

Equation 1

First year non-capacity revenues in our analysis are consistent with the assumptions specified in the tariff for the cost of capital. For this reason, we estimated first year non-capacity revenues that could be expected to be negotiated as part of a PPA. We estimate PPA-based revenues for 2018-19 using historical energy and ancillary services revenues adjusted based on estimated futures prices for those years, to the extent available. Futures prices can be locked in at the present time in advance of the delivery date and provide a reasonable indicator of contract prices for the purposes of this analysis.

The sections below present the methodology used to estimate energy, ancillary service, and REC revenues as well as the value of transmission and distribution (T&D) investment avoidance/delay that energy efficiency programs provide.

1. E&AS Revenues

The first year energy and ancillary services (E&AS) margins for each generation technology have been calculated based on historical revenues with adjustments based on currently available gas and electricity futures prices.

The historical E&AS margins for each resource type are calculated from the revenues and estimated variable fuel and O&M costs for "like units" in 2010, 2011, and 2012. The like units were identified based on the performance (*i.e.*, heat rate) and location of the resources that most closely align with the technical specifications of the resource type being considered. From ISO-NE market data, monthly total revenues were calculated for each like unit from 2010 to 2012 and normalized based on the nameplate capacity of the units.[34] Longer time periods were considered, however differences in the market conditions and fuel prices prior to 2010 significantly skew the results based on conditions that no longer persist.

Historical margins for the like units were calculated by subtracting the variable costs for each unit from the total revenues. The variable costs for each plant were calculated based on fuel usage, historical spot gas prices, and variable O&M values estimated by S&L.

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34 Total revenues included day-ahead and real-time energy revenues, net commitment period compensation (NCPC) credits, regulation revenues, blackstart payments, VAR capacity cost payments, and real-time reserves.

Once historical E&AS margins were determined, the 2018/2019 E&AS margins were estimated based on the ratio of future electricity prices to historical electricity prices using Mass Hub On-Peak as the reference hub,[35] as shown in Equation 2.

$$2018/19\ E\&AS\ Margin = Historical\ E\&AS\ Margin * \frac{2018/2019\ Mass\ Hub\ On\ Peak\ Prices}{Historical\ Mass\ Hub\ On\ Peak\ Prices}$$

Equation 2

As trading in Mass Hub futures is generally limited to deliveries over the next 12 months, the 2018/2019 Mass Hub On-Peak prices were estimated based on 2018/2019 Henry Hub futures and the basis differential and market heat rates (i.e., the power price divided by the gas price) implied by the Algonquin City-Gates and Mass Hub On-Peak prices for the next 12 months. The basis differential between Henry Hub and Algonquin City-Gates was calculated for the next twelve months and held constant in real terms out to 2018/2019. Similarly, the Algonquin City-Gates gas prices and Mass Hub On-Peak electricity prices for the same twelve month-time period were used to calculate the implied market heat rate. The implied market heat rate was assumed to remain constant through 2018/2019.[36] The equation for calculating 2018/2019 Mass Hub On-Peak prices is shown in Equation 3.

$$\begin{aligned} 2018/2019\ Mass\ Hub\ On\ Peak\ Prices & \\ = 2013/2014\ Market\ Heat\ Rate & \\ * (2018/2019\ Henry\ Hub + 2013/2014\ Basis\ Differential) & \end{aligned}$$

Equation 3

This approach is a proxy for a PPA-supported forward energy price that accounts for the effect of rising gas prices. It does not account for changes in future market conditions beyond what is implied by futures prices over the next twelve months, such as how market heat rates might change as reserve margins tighten, nor does it fully account for the growing discount one would expect for forward prices relative to expected spot prices for longer forward periods.[37] However, it is an improvement on methods that rely solely on historical margins for calculating Net CONE.

Based on this method, we have projected 2018/2019 electricity prices as shown in Figure 3 with futures market data shown in bold lines and projected prices in dotted lines.

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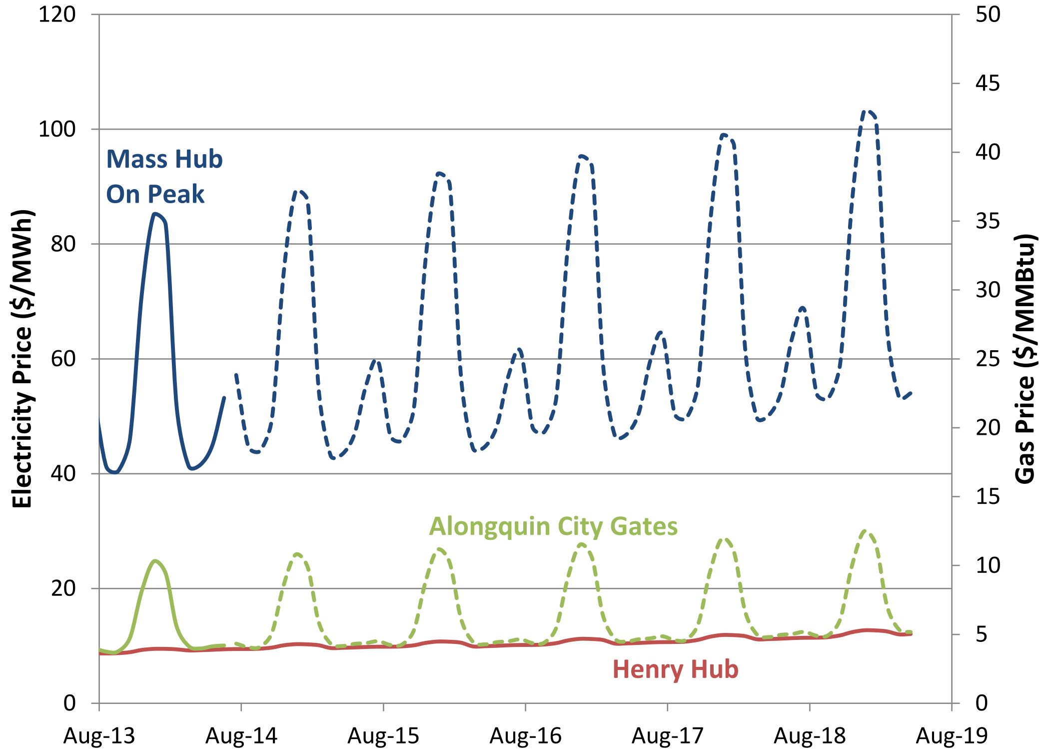
35 Mass Hub was chosen due to its location in a non-constrained zone and the volume of trading of Mass Hub electricity futures.

36 Although the market is expected to get tighter prior to the FCA9 commitment period, we did not find a reasonable basis for making a specific adjustment to the market heat rate implied by the short term futures prices that would properly account for future changes in market conditions.

37 This assumption generally is true for any pro-cyclic commodity, such as natural resources and electricity.

Figure 3
Projected New England Gas and Electricity Prices



Source and Notes: Solid lines are based on futures prices from SNL, 2013. Dashed lines are calculated based on formulas above.

A stakeholder asked whether forward reserve market (FRM) revenues, which have been increasing recently, are considered in the analysis. FRM payments have not been included because there is not yet enough data to determine how much benefit a new combustion turbine would derive, if any, from selling FRM and foregoing future E&AS revenues.

2. Renewable Energy Credits

For projecting the contracted value of RECs for the 2018/2019 period, we have used an approach similar to the E&AS margin projections. Currently, RECs in Massachusetts and Connecticut are selling very close to the ceiling prices set by the Alternative Compliance Payment (ACP) value in each state due to a temporary short-term shortage in RECs.[38] It is likely that the spot market for RECs will maintain this level close to the ACP into the future due to the increasing levels of renewable generation required for compliance with Renewable Portfolio Standards (RPS) across New England.[39]

38 CT DEEP, 2013.

39 The ACP value in Massachusetts, which has the largest REC demand, is $65.27/MWh for 2013. The 2018 value assuming 2.25% inflation is $72.95/MWh.

However, REC spot prices are highly uncertain due to market factors as well as regulatory risks, including changes to RPS rules and state procurement practices. A contract price, by contrast, is a "sure thing" for which developers would be expected to be willing to accept a significant discount from the expected spot price. Taking these factors into account, we have projected future REC prices based on the current price information available for 2016 vintage Massachusetts Class I RECs, the most forward looking prices available, which is $46.6 per megawatt-hour.[40] The 2018/2019 REC price of $49.3 per megawatt-hour was calculated by escalating the 2016 value at the assumed rate of inflation.

3. Energy Efficiency Benefits

For energy efficiency resources, we considered the non-capacity "revenues" to be the energy savings that result from the reduction in energy usage, based on wholesale prices. Wholesale energy prices are a more appropriate measure of non-capacity value than avoided retail generation rates, since those include a capacity payment. We also included the value of avoiding or delaying transmission and distribution investments due to moderated system peak loads. (This economic savings is a more appropriate measure of value than avoided retail T&D rates, since avoiding the full retail rate just shifts fixed costs to other ratepayers).

To estimate the energy savings per megawatt of energy efficiency, we relied on the annual energy savings (MWh) estimated for each state program and assumed the energy savings for a typical program would generally follow the hourly load shape for ISO-NE's total load. We valued such hourly savings using the historical Mass Hub locational marginal price (LMP) from 2010-2012, with adjustments based on futures prices, similar to our calculation of future E&AS margins for generation resources. The resulting load-weighted average electricity price of the avoided energy in 2018/2019 was $62.6 per megawatt-hour.

For the value of T&D investment avoidance and delay, we used the avoided T&D costs assumed by the Connecticut utilities in their cost-benefit tests of $35.9 per kilowatt-year, and escalated the value to 2018 dollars, $40.6 per kilowatt-year.[41]

F. ORTP Calculation

The ORTP value for each technology has been calculated based on our analysis of the Net CONE within the guidelines defined by the tariff and presented in terms of nominal dollars per kilowatt of qualified capacity per month. The qualified capacity for new non-intermittent resources is the capacity that is projected to be available from the resource during the summer and winter peak

40 The value for 2016 vintage Massachusetts Class I RECs is from SNL data as of August 23, 2013.

41 CL&P, *et al.*, 2012, p. 307.

periods.[42] Consistent with IMM reviews and the previous ORTP analysis, we have assumed that non-intermittent resources are available at their nameplate capacity. For new intermittent resources, the qualified capacity has been calculated based on values available in the ISO-NE Seasonal Claimed Capability database for existing units as the qualified capacity calculation methodology for intermittent resources is similar to that used to develop the Seasonal Claimed Capability values.

42 The qualified MW value for an existing capacity resource for each FCA qualification period will be the median of the last five positive summer Seasonal Claimed Capability (SCC) ratings using the summer SCC data available in October.

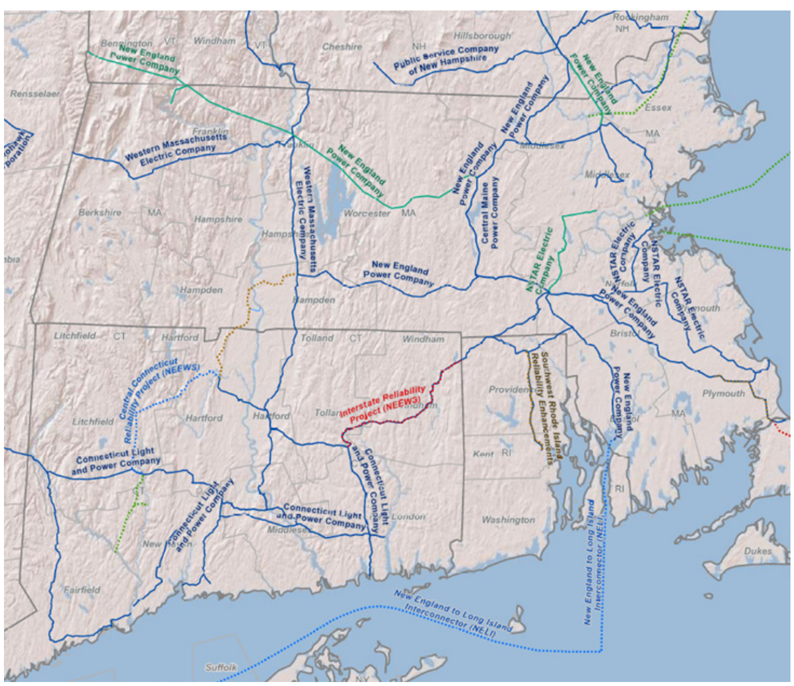
III. Combined Cycle Gas Turbine ORTP

A. Technical Specifications

We determined the technical specifications of the combined cycle gas turbine plant (CCGT) primarily based on the choices that developers have recently found to be most feasible and economic, as observed in recently constructed and planned units across the U.S. and in New England. However, because technologies and environmental regulations continue to evolve, we supplemented the actual observations with guidance from S&L and with additional analysis of underlying economics, regulations, and infrastructure.

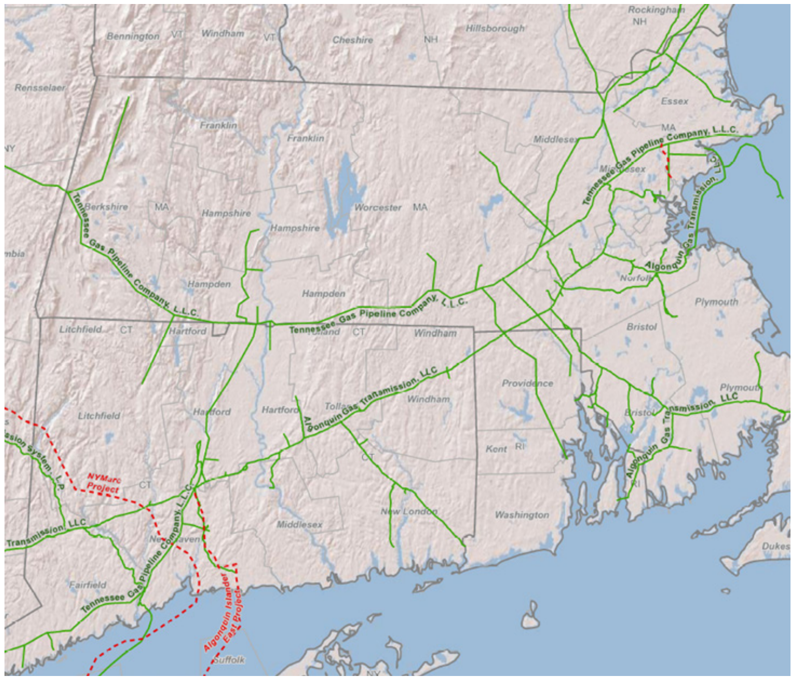
We first conducted a siting evaluation to select a specific county to use as the cost estimate basis for the combined cycle plants. Our goal was to identify a favorable site that a competitive developer could reasonably find in New England. Thus we sought a location with unconstrained high voltage transmission infrastructure and major gas pipelines and without major siting encumbrances. Western Massachusetts and northern Connecticut fit those criteria, with Hampden County in south-western Massachusetts being a prime candidate. We have chosen Hampden County as the basis for our analysis representative of that region. Figure 4 and Figure 5 show the electric transmission systems and gas pipelines in the area considered.

Figure 4
Electric Transmission Systems in Massachusetts and Connecticut



Source: SNL, 2013.

Figure 5
Major Gas Pipelines in Massachusetts and Connecticut



Source: SNL, 2013.

Next, we determined plant size and configuration for the CCGT plant based on a review of projects currently in development or built since 2010. Only the Kleen Energy Project in Connecticut has entered in that timeframe. It has a summer capacity of 620 MW with a 2x1 configuration (two gas turbines with a single steam turbine) and is similar to the predominant configuration built in other regions. Table 7 shows the capacity additions of CCGTs across the U.S. since 2010 for several capacity sizes. As the table shows, most new CCGTs are 500-700 MW in a 2x1 configuration.

Table 7
U.S. CCGT Plants Under Construction or Built Since 2010

	< 300 *(MW)*	300-500 *(MW)*	500-700 *(MW)*	700-900 *(MW)*	900-1100 *(MW)*	1100-1300 *(MW)*	> 1300 *(MW)*	**Total *(MW)***
2 x 1	762	1,732	12,064	4,856	0	0	0	**19,414**
2 x 2	0	0	560	0	0	0	0	**560**
3 x 1	170	0	545	880	950	4,969	0	**7,514**
Total	**931**	**1,732**	**13,169**	**5,736**	**950**	**4,969**	0	**27,487**

Source: Ventyx, 2013

We determined the predominant turbine model for CCGT plants by reviewing the turbines that have recently been installed. Table 8 shows turbine models by total installed capacity in the U.S. since 2010. The most common turbine models are GE 7FA, Mitsubishi M501G, and Siemens

SGT6-5000F. Mitsubishi M501G models appear to be installed at plants with an installed capacity much larger than the 500-700 MW range.

We chose the Siemens SGT6-5000F turbine over the GE 7FA as it was installed at Kleen Energy Project, the most recent project in New England, and at West Deptford, a CCGT plant currently under construction in PJM.[43]

Table 8
Turbine Models of U.S. CCGT Plants Since 2010

Turbine Model	ISO-NE		U.S.		Avg. Plant Size
	(MW)	*(count)*	*(MW)*	*(count)*	*(MW)*
General Electric Co-MS7001FA GT	0	0	4,317	7	617
Mitsubishi Heavy Industries-M501G	0	0	3,751	4	938
Siemens Power Generation Inc-SGT6-5000F	620	1	3,334	6	556
General Electric Co-PG7241(FA)	0	0	972	2	486
General Electric Co-MS7001EA	0	0	864	4	216
Siemens Power Generation Inc-SCC6-5000F	0	0	809	1	809
Siemens Power Generation Inc-Flex-Plant 30	0	0	809	1	809
Siemens AG-501G	0	0	695	1	695
Siemens Power Generation Inc-501FD	0	0	620	1	620
Siemens Power Generation Inc-V84.2	0	0	545	1	545
Siemens AG-501F	0	0	544	1	544
General Electric Co-S107H	0	0	366	1	366
General Electric Co-LM6000PC Sprint	0	0	308	1	308
General Electric Co-MS7001FA CC	0	0	290	1	290
General Electric Co-GE LM6000	0	0	200	2	100
General Electric Co-PGS6001B Frame 6B	0	0	46	1	46

Sources and Notes: Ventyx, 2013. This database is not comprehensive in identifying all turbine models, with approximately 60% of the total MW installed since 2010 being identified by turbine model type in the database.

For the reference CCGT plant, we assumed duct-firing capability consistent with recent projects in ISO-NE and the rest of the U.S. Existing CCGT plants in ISO-NE, such as Kleen, Mystic, and Fore River, have duct firing.[44] Kleen's duct firing accounts for 100 MW of its 620 MW of installed capacity. In addition, Footprint Power's proposed 692 MW Salem Harbor gas CC plant will include 62 MW of duct firing capability.[45] Table 9 shows that duct firing added 13% additional capacity to CCGT plants in the U.S. on average, compared to 19% for Kleen Energy. For the CCGT technical specifications, we assumed that duct firing would expand plant capacity by 15%.

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43 Plant specifications obtained from SNL (2013).

44 Ventyx, 2013.

45 DeTore, *et al.*, 2013.

Table 9
Duct-Firing Capability of Gas CCGT Plants Constructed Since 2010 and In Development

	Installed Capacity *(MW)*	No. of Plants *(count)*	Avg. Plant Size *(MW)*	Avg. Duct Fired Capacity *(MW)*	Duct Fired Addition % *(%)*
ISO-NE	620	1	620	100	19%
U.S.	9,868	13	759	85	13%

Sources and Notes: Duct firing capacities for CCGT plants with duct firing capability compiled by Ventyx, 2013.

Based on the selected Siemens turbine in a 2x1 configuration with duct firing, the net plant capacity is 730 MW and the net heat rate is 7,526 BTU/kWh at maximum output. When the unit is not utilizing its duct firing capacity, the net plant capacity is 631 MW and the net heat rate is 7,204 BTU/kWh.

As requested by ISO-NE market participants, we considered whether newly-available flexible design packages, such as the GE FlexEfficiency 60, should be included in our design specifications. Although it appears the flexible design is planned for the Footprint project, we conclude that the Siemens SGT6-5000F can perform well enough to capture most of the performance incentives the ISO-NE market is likely to offer.[46] The Flex design might provide some additional revenues, but at an incremental cost. We chose not to include the incremental costs because our methodology was unlikely to capture the types of incremental revenues the Flex design might achieve. Our approach for calculating non-capacity revenues is based on historical revenues of like plants, which do not include any Flex designs.

The reference CCGT plant also includes the following design specifications that are likely to be standard practice for the region:

- **Dry Cooling** avoids violating pending regulations on cooling water withdrawals.[47]
- **Evaporative Cooling** provides power augmentation, increasing the output substantially for only a small increase in cost, consistent with industry standard practice.

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[46] The assumed plant can achieve 150 MW in 10 minutes and full output of the combustion turbines in less than 20 minutes. The full CCGT output can be achieved in 40 minutes for a hot start and 125 minutes for a cold start, assuming the plant is able to purge gas out of the heat recovery steam generator ("HRSG") before each start.

[47] According to the EIA-860 Database, the majority of the cooling water systems installed in the past 15 years at electric generating facilities in Massachusetts have been dry (air) cooling systems. EIA, 2013a.

- **Environmental Controls** include dry low NO_x burners and Selective Catalyst Reduction (SCR) for reducing NO_x emissions and CO catalyst.[48]

- **Dual-Fuel Capability** includes a three-day supply of ultra-low sulfur diesel (ULSD) due to growing concerns in New England about reliability issues caused by the over-reliance of the system on non-firm natural gas.

- **Black Start Capability** is not included as few recently built CCGTs have such capability.

- **On-Site Gas Compression** is not needed since the pipeline pressure is high enough for a CCGT plant.

- **345 kV Interconnection** is appropriate for the location we have chosen.

Table 10 below summarizes the assumed technology specifications for the reference CCGT plant.

48 The entire state of Massachusetts is designated as attainment and/or unclassifiable except Dukes County; however, because Massachusetts is within the Ozone Transport Region, NOx and VOC are considered nonattainment pollutants within the entire state. NOx control equipment and a catalytic oxidation system for CO/VOC control are included as a result of the state being within the Ozone Transport Region.

Table 10
Technical Specifications
Reference CCGT Plant

Unit Specifications	Combined Cycle Gas Turbine
Turbine Model	Siemens SGT6-5000F(5)
Primary Fuel	Natural Gas
Configuration	2 x 2 x 1
Net Plant Capacity (MW)	730
without Duct Firing (MW)	631
Cooling System	Dry
Power Augmentation	Evaporative Cooling No inlet chillers
Net Heat Rate (Btu/kWh,HHV)	7,526
without Duct Firing (Btu/kWh, HHV)	7,204
Qualified Capacity	100%
Environmental Controls	Dry Low NOx Burners SCR CO Catalyst
Dual Fuel Capability	ULSD
Blackstart Capability	No
On-Site Gas Compression	No
Interconnection	345 kV
Plot Size (acres)	20
Location	Hampden County, MA

B. Capital Costs

S&L provided capital cost estimates for the reference CCGT plant, as summarized in Table 11 below and explained further in the Technical Appendix. Brattle estimated gas and electric interconnection costs, as explained further below. The estimated overnight cost for the CCGT plant is $808 million in 2018 dollars, or $1,108/kW.

Table 11
Overnight Capital Costs
Reference CCGT Plant

	2013 Overnight Costs *(2013 $)*	2013 Overnight Costs *(2013 $/kW)*	2018 Overnight Costs *(2018 $/kW)*
EPC Costs			
Equipment			
Gas Turbines	$90,000,000	$123	$141
Boiler / HRSG / SCR	$43,000,000	$59	$67
Condenser	$26,900,000	$37	$42
Steam Turbines	$36,000,000	$49	$56
Other Equipment	$50,093,000	$69	$78
Construction Labor	$154,140,000	$211	$254
Other Labor	$36,833,000	$50	$61
Materials	$33,198,000	$46	$52
Sales Tax	$17,449,000	$24	$27
EPC Contractor Fee	$58,514,000	$80	$93
EPC Contingency	$54,613,000	$75	$87
Total EPC Costs	**$600,740,000**	**$823**	**$959**
Non-EPC Costs			
Owner's Costs (Services)	$42,052,000	$58	$67
Electrical Interconnection	$16,000,000	$22	$25
Gas Interconnection	$3,600,000	$5	$6
Fuel Inventories	$7,499,000	$10	$11
Working Capital	$6,007,000	$8	$10
Owner's Contingency	$6,013,000	$8	$9
Financing Fees	$13,638,000	$19	$22
Total Non-EPC Costs	**$94,809,000**	**$130**	**$149**
Overnight Capital Costs ($)	**$695,549,000**	**$953**	**$1,108**

Electrical interconnection costs are based on our review of system impact studies from new and planned projects. We concluded that because projects have not consistently needed network upgrades and because the reference CCGT is assumed to be located in an area with robust networks, only direct assignment facilities would be required for electrical interconnection. Table 12 shows the assumed equipment required for the direct assignment facilities and the costs developed from the ISO-NE Transmission Project Listing.[49] The estimated electrical interconnection cost for the CCGT plant is $16 million or $21.9/kW.

[49] ISO-NE, 2013c.

Table 12
Electrical Interconnection Equipment and Costs
Reference CCGT Plant

Component	***Quantity*** *(#)*	***Unit Price*** *(m$)*	***Cost*** *(m$)*
345 kV Transmission Line (miles)	0	4.5	$0.0
Substation Equipment (breakers)	2	2.0	$4.0
Substation Buildout	1	12.0	$12.0
Total (m$)			**$16.0**
Total ($/kW)			**$21.9**

Notes: All costs are shown in 2013 dollars.

For gas interconnection costs, we have assumed that a developer will locate in close proximity to the existing gas pipelines such that additional pipeline is not required for interconnecting but a metering station is necessary, as shown in Table 13. The unit costs are based on a recent study we conducted for PJM,[50] escalated from 2011 to 2013 dollars using the assumed rate of inflation of 2.25%. The resulting estimated gas interconnection cost for the CCGT plant is $3.6 million or $4.9/kW.

Table 13
Gas Interconnection Equipment and Costs
Reference CCGT Plant

Component	***Quantity*** *(#)*	***Unit Price*** *(m$)*	***Cost*** *(m$)*
Pipeline (miles)	0	2.5	$0.0
Metering Station	1	3.6	$3.6
Total (m$)			**$3.6**
Total ($/kW)			**$4.9**

Notes: All costs are shown in 2013 dollars.

We calculated the capital cost during construction and the installed cost of the CCGT using the construction drawdown schedule provided by Sargent & Lundy. For the CCGT plant, the construction drawdown schedules occurs over 36 months with 80% of the costs incurred in the final 20 months prior to commercial operation, as shown in the Appendix. Based on the construction cash flows, the interest during construction (IDC) for the CCGT is $25 million assuming 50% debt financing. The installed cost, which also includes the equity component of the cost of capital during construction, is $878 million or $1,203/kW.

50 Spees, *et al.,* 2011.

C. Fixed O&M Costs

S&L estimated fixed O&M costs based on its experience and the following assumptions specific to the technical specifications of the reference CCGT plant.

The plant owner leases 20 acres of industrial land in Hampden County at a market rate of \$19,000/acre-year. The leasing costs of \$19,000/acre-year were estimated from recent listings for industrial real estate in Massachusetts, which ranged from approximately \$1,000/acre-year to \$25,000/acre-year. Considering the need for proximity to gas and transmission interconnection, a value at the high end of the range was selected. The annual leasing cost for the CCGT is \$380,000 per year in 2013 dollars.

The property tax rate of 0.75% of the overnight capital cost per year was estimated from a sample of independent power projects in New England that have entered into agreements for payments in lieu of taxes (PILOT) based on common practice in the industry with local jurisdictions. In Hampden County, MA, commercial and industrial property tax rates typically range from about \$15 to \$30 per \$1000 of assessed value (or 1.50% to 3.00%). Projects with PILOT agreements typically have rates between 0.25% to 1.00%, assuming a newer plant and no change in assessed valuation over the term of the agreement. Based on the rate of 0.75%, the property tax for the CCGT plant was estimated at \$5.2 million per year in 2013 dollars.

We calculated insurance cost at 0.6% of the overnight capital cost, based on a sample of independent power projects recently under development in the Northeastern US and discussions with a project developer. Annual insurance for the CCGT plant was estimated at \$4.2 million per year in 2013 dollars.

From these assumptions, we calculated for the CCGT plant a fixed O&M cost of \$24.01/kW-yr in 2013, escalated to \$27.90/kW-yr in 2018 dollars. Table 14 summarizes the fixed O&M costs for the CCGT plant.

Table 14
Fixed Operating and Maintenance Costs
Reference CCGT Plant

	2013 Costs *(2013$)*	2018 Costs *(2018$)*
Fixed O&M		
Labor	$2,938,000	$3,532,000
Materials and Contract Services	$4,018,000	$4,579,000
Administrative and General	$793,000	$904,000
Site Leasing Costs	$380,000	$425,000
Property Taxes	$5,219,000	$6,066,000
Insurance	$4,173,000	$4,850,000
Total Fixed O&M ($)	**$17,521,000**	**$20,356,000**
Total Fixed O&M ($/kW-year)	**$24.01**	**$27.90**

D. Revenue Offsets

The revenue offsets for the reference CCGT plant derive solely from energy and ancillary service (E&AS) margins. ISO-NE provided historical actual revenue data for 15 CCGT plants that we identified with similar characteristics to the reference plant. We subtracted fuel and variable O&M costs to estimate historical E&AS margins.[51] As Table 15 shows, the 2010 – 2012 average E&AS margins for these CCGTs was $3.13/kW-mo, and the projected 2018/19 margin is estimated to be $3.75/kW-mo.

Table 15
Historical and Projected E&AS Margins
Gas CCGT Plants

	Historical Actuals			Future Projections						
($/kW-mo)	2010	2011	2012	2013	2014	2015	2016	2017	2018	**2018/19**
CCGT	$3.30	$3.15	$2.92	$3.35	$3.31	$3.43	$3.52	$3.61	$3.71	**$3.75**

Notes: All values are shown in nominal dollars.

51 Historical fuel costs were obtained from their Form 923 filings with the Energy Information Administration ("EIA"). (EIA, 2013b) For the variable O&M cost, we used $2.34/MWh for the CCGT plants provided by S&L based on its experience.

E. ORTP Calculation

Based on the cost estimates, financial assumptions, and projected revenues escalation rate, the first year revenue requirement, or Gross CONE, for the CCGT such that the NPV equals zero is $12.61/kW-mo. The components of Gross CONE are shown in Table 16.

The first year revenue offset derived from E&AS margins is $3.75/kW-mo. The Net CONE value for the CCGT is therefore estimated to be $8.87/kW-mo. We recommend the ORTP value for CCGT to be $8.866/ kW-mo.

Table 16
Combined Cycle Gas Turbine ORTP Calculation

Installed Capacity	MW	730
Qualified Capacity	%	100%
Capital Costs (Installed)	$/kW	1,203
ATWACC	%	7.2%
Revenue Escalation Rate	%/yr	2.25%
Depreciation Schedule		20yr MACRS
Gross CONE	*$/kW-mo*	*12.61*
Capital Costs	$/kW-mo	13.17
Fixed O&M	$/kW-mo	2.33
Depreciation Tax Shield	$/kW-mo	-2.88
Revenue Offsets	*$/kW-mo*	*3.75*
E&AS Margins	$/kW-mo	3.75
Net CONE (Installed)	*$/kW-mo*	*8.87*
Net CONE (Qualified)	*$/kW-mo*	*8.87*
ORTP	**$/kW-mo**	**8.866**

IV. Combustion Turbine ORTP

A. Technical Specifications

We determined the technical specifications of the combustion turbine plant (CT) primarily based on the choices developers have made for new and planned units in New England and the rest of the U.S. However, because technologies and environmental regulations continue to evolve, we supplemented the actual observations with guidance from S&L and with additional analysis of underlying economics, regulations, and infrastructure.

Siting criteria of the CT plant are similar to those for the combined cycle plant, discussed in Section III.A, leading to the same Hampden County, Massachusetts location.

To determine the technical specifications, we researched turbine models in new and planned plants. Table 17 shows the amount of capacity currently in development and installed in the United States since 2012 by turbine type, as well as the average size of the turbine. The GE LMS100 model (including both the PA and PB options) is the most common simple-cycle turbine installed recently, closely followed by the Siemens SGT6-5000F and the GE LM6000.

Table 17
Gas CT Plants Installed by Turbine Type Since 2012

	ISO-NE		U.S.		Avg. Unit Size
	(MW)	*(count)*	*(MW)*	*(count)*	*(MW)*
Siemens Power Generation Inc-SGT6-5000F	0	0	1,511	8	189
General Electric Co-LMS100PA-SAC (Water)	0	0	850	8	106
General Electric Co-LMS100PB-DLE2	0	0	769	8	96
General Electric Co-GE LM6000	134	3	305	7	44
General Electric Co-LM6000PC Sprint	0	0	246	5	49
General Electric Co-GE LM6000 PG	0	0	150	3	50
General Electric Co-PG7241(FA)	0	0	145	1	145

Sources and Notes: Ventyx, 2013. This database is not comprehensive in identifying turbine models, with about 60% of the total MW installed since 2010 being identified by turbine model type.

We chose the GE LMS100 PA model for the reference plant based on its predominance, size, and heat rate. We assumed a 2x0 configuration to reduce the impact of common costs on a per kilowatt basis. Based on the turbine and configuration chosen, the net plant capacity of the CT plant is 192 MW and the net heat rate of the CT plant is 9,244 BTU/kWh.

In addition, the following design considerations were made in setting the reference CT technical specifications:

- **Dry Cooling** avoids violating pending regulations on cooling water withdrawals.[52]
- **Evaporative Cooling** provides power augmentation, increasing the output substantially for only a small increase in cost, consistent with industry standard practice.
- **Environmental Controls** include water injection NO_x control and Selective Catalyst Reduction (SCR) for reducing NO_x emissions and CO catalyst.[53]

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52 According to the EIA-860 Database, the majority of the cooling water systems installed in the past 15 years at electric generating facilities in Massachusetts have been dry (air) cooling systems. EIA, 2013a.

53 The entire state of Massachusetts is designated as attainment and/or unclassifiable except Dukes County; however, because Massachusetts is within the Ozone Transport Region, NOx and VOC are considered nonattainment pollutants within the entire state. NOx control equipment and a catalytic

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- **Dual-Fuel Capability** includes a three-day supply of ultra-low sulfur diesel (ULSD) due to growing concerns in New England about reliability issues caused by the over-reliance of the system on non-firm natural gas.

- **Black Start Capability** is not included as few recently built CTs have such capability.

- **On-Site Gas Compression** is needed since the pipeline pressure is not high enough for a CT plant.

- **345 kV Interconnection** is appropriate for the location we have chosen.

Table 18 below summarizes the technology specifications for the reference CT plant.

Table 18
Technical Specifications
Reference CT Plant

Unit Specifications	Combustion Turbine
Turbine Model	GE LMS100 PA
Primary Fuel	Natural Gas
Configuration	2 x 0
Net Plant Capacity (MW)	192
Cooling System	Dry
Power Augmentation	Evaporative Cooling No inlet chillers
Net Heat Rate (Btu/kWh,HHV)	9,244
Qualified Capacity	100%
Environmental Controls	Water Injection NOx Control SCR CO Catalyst
Dual Fuel Capability	ULSD
Blackstart Capability	No
On-Site Gas Compression	Yes
Interconnection	345 kV
Plot Size (acres)	10
Location	Hampden County, MA

B. Capital Costs

S&L provided capital cost estimates for the reference CT plant, as summarized in Table 19 below and explained further in the Technical Appendix. Brattle estimated gas and electric

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oxidation system for CO/VOC control are included as a result of the state being within the Ozone Transport Region.

interconnection costs, as explained further below. The estimated overnight cost for the CT plant is $305 million in 2018 dollars, or $1,583/kW.

Table 19
Overnight Capital Costs
Reference CT Plant

	2013 Overnight Costs *(2013 $)*	**2013 Overnight Costs** *(2013 $/kW)*	**2018 Overnight Costs** *(2018 $/kW)*
EPC Costs			
Equipment			
Gas Turbines	$77,500,000	$403	$459
Boiler / HRSG / SCR	$14,000,000	$73	$83
Other Equipment	$29,013,000	$151	$172
Construction Labor	$38,612,000	$201	$241
Other Labor	$14,121,000	$73	$88
Materials	$7,007,000	$36	$42
Sales Tax	$7,970,000	$41	$47
EPC Contractor Fee	$18,822,000	$98	$113
EPC Contingency	$20,705,000	$108	$125
Total EPC Costs	**$227,750,000**	**$1,184**	**$1,370**
Non-EPC Costs			
Owner's Costs (Services)	$15,943,000	$83	$96
Electrical Interconnection	$4,000,000	$21	$24
Gas Interconnection	$3,600,000	$19	$21
Fuel Inventories	$2,529,000	$13	$14
Working Capital	$2,278,000	$12	$14
Owner's Contingency	$2,268,000	$12	$13
Financing Fees	$5,167,000	$27	$31
Total Non-EPC Costs	**$35,785,000**	**$186**	**$213**
Overnight Capital Costs ($)	**$263,535,000**	**$1,370**	**$1,583**

To estimate the electrical interconnection cost of the reference CT plant, we reviewed system impact studies from recent and planned projects. We concluded that because projects have not consistently needed network upgrades and because the reference CT plant is assumed to be located in an area with robust networks, only direct assignment facilities would be required for electrical interconnection. Table 20 shows the assumed equipment required for the direct assignment facilities and the costs developed from the ISO-NE Transmission Project Listing.[54] The estimated electrical interconnection cost for the reference CT plant is $4 million in 2013 dollars, or $20.8/kW.

[54] ISO-NE, 2013c.

Table 20
Electrical Interconnection Equipment and Costs
Reference CT Plant

Component	*Quantity (#)*	*Unit Price (m$)*	*Cost (m$)*
345 kV Transmission Line (miles)	0	4.5	$0.0
Substation Equipment (breakers)	2	2.0	$4.0
Total (m$)			**$4.0**
Total ($/kW)			**$20.8**

Notes: All costs are shown in 2013 dollars.

For gas interconnection, we have also assumed that an additional pipeline is not required for interconnecting but that a metering station is necessary. The unit costs are based on a recent study we conducted for PJM,[55] escalated from 2011 to 2013 dollars using the assumed rate of inflation of 2.25%. The resulting gas interconnection cost estimate for the CT plant is $3.6 million in 2013 dollars, or $18.7/kW.

Table 21
Gas Interconnection Equipment and Costs
Reference CT Plant

Component	*Quantity (#)*	*Unit Price (m$)*	*Cost (m$)*
Pipeline (miles)	0	2.5	$0.0
Metering Station	1	3.6	$3.6
Total (m$)			**$3.6**
Total ($/kW)			**$18.7**

Notes: All costs are shown in 2013 dollars.

C. Fixed O&M Costs

S&L estimated fixed O&M costs based on its experience and the following assumptions specific to the technical specifications of the reference CT plant.

The plant owner leases 10 acres of industrial land in Hampden County at a market rate of $19,000/acre-year. The leasing costs of $19,000/acre-year were estimated from recent listings for industrial real estate in Massachusetts, which ranged from approximately $1,000/acre-year to $25,000/acre-year. Considering the need for proximity to gas and transmission interconnection,

55 Spees, *et al.*, 2011.

a value at the high end of the range was selected. The annual leasing cost for the CT is $190,000 per year in 2013 dollars.

The property taxes of 0.75% of the overnight capital cost per year were estimated from a sample of independent power projects in New England that have entered into agreements for payments in lieu of taxes (PILOT) with local jurisdictions. In Hampden County, MA, commercial and industrial property tax rates typically range from about $15 to $30 per $1000 of assessed value (or 1.50% to 3.00. Projects with PILOT agreements typically have rates between 0.25% to 1.00%, assuming a newer plant and no change in assessed valuation over the term of the agreement. Based on the rate of 0.75%, the property tax for the CT plant was estimated at $2.0 million per year in 2013 dollars.

We calculated insurance cost at 0.6% of the overnight capital cost, based on a sample of independent power projects recently under development in the Northeastern U.S. and discussions with a project developer. Annual insurance for the CT plant was estimated at $1.6 million per year in 2013 dollars.

From these assumptions, we calculated for the CT plant a fixed O&M cost of $27.42/kW-yr in 2013, escalated to $31.81/kW-yr in 2018 dollars. Table 22 summarizes the fixed O&M costs for the CT plant.

Table 22
Fixed Operating and Maintenance Costs
Reference CT Plant

	2013 Costs *(2013$)*	2018 Costs *(2018$)*
Fixed O&M		
Labor	$882,000	$1,060,000
Materials and Contract Services	$308,000	$351,000
Administrative and General	$335,000	$382,000
Site Leasing Costs	$190,000	$212,000
Property Taxes	$1,978,000	$2,286,000
Insurance	$1,581,000	$1,827,000
Total Fixed O&M ($)	**$5,274,000**	**$6,118,000**
Total Fixed O&M ($/kW-year)	**$27.42**	**$31.81**

D. REVENUE OFFSETS

The revenue offsets for the reference CT plant derive solely from energy and ancillary service margins. ISO-NE provided historical actual revenue data for 8 CT plants we identified with similar characteristics to the reference plant. We subtracted fuel and variable O&M costs to estimate historical E&AS margins.[56] As Table 23 shows, the 2010 – 2012 average E&AS margins for these CTs was $2.27/kW-mo, and the projected 2018/19 margin is estimated to be $2.71/kW-mo.

Table 23
Historical and Projected E&AS Margins
Gas CT Plants

	Historical Actuals			Future Projections						
($/kW-mo)	2010	2011	2012	2013	2014	2015	2016	2017	2018	**2018/19**
CT	$2.46	$2.34	$2.01	$2.47	$2.38	$2.47	$2.54	$2.60	$2.67	**$2.71**

Notes: All values are shown in nominal dollars.

E. ORTP Calculation

Based on the cost estimates, financial assumptions, and projected revenues escalation rate, the first year revenue requirement, or Gross CONE, for the CT such that the NPV equals zero is $16.13/kW-mo. The components of Gross CONE are shown in Table 24.

The first year revenue offset derived from E&AS margins is $2.71/kW-mo. The Net CONE value for the CT is therefore estimated to be $13.42/kW-mo. Assuming 100% of nameplate capacity qualifies as "qualified capacity," we recommend the ORTP value for CT to be $13.424/ kW-mo.

[56] Historical fuel costs were obtained from their Form 923 filings with the Energy Information Administration ("EIA"). (EIA, 2013b) For the variable O&M cost, we used $2.34/MWh for the CCGT plants provided by S&L based on its experience.

Table 24
Combustion Turbine ORTP Calculation

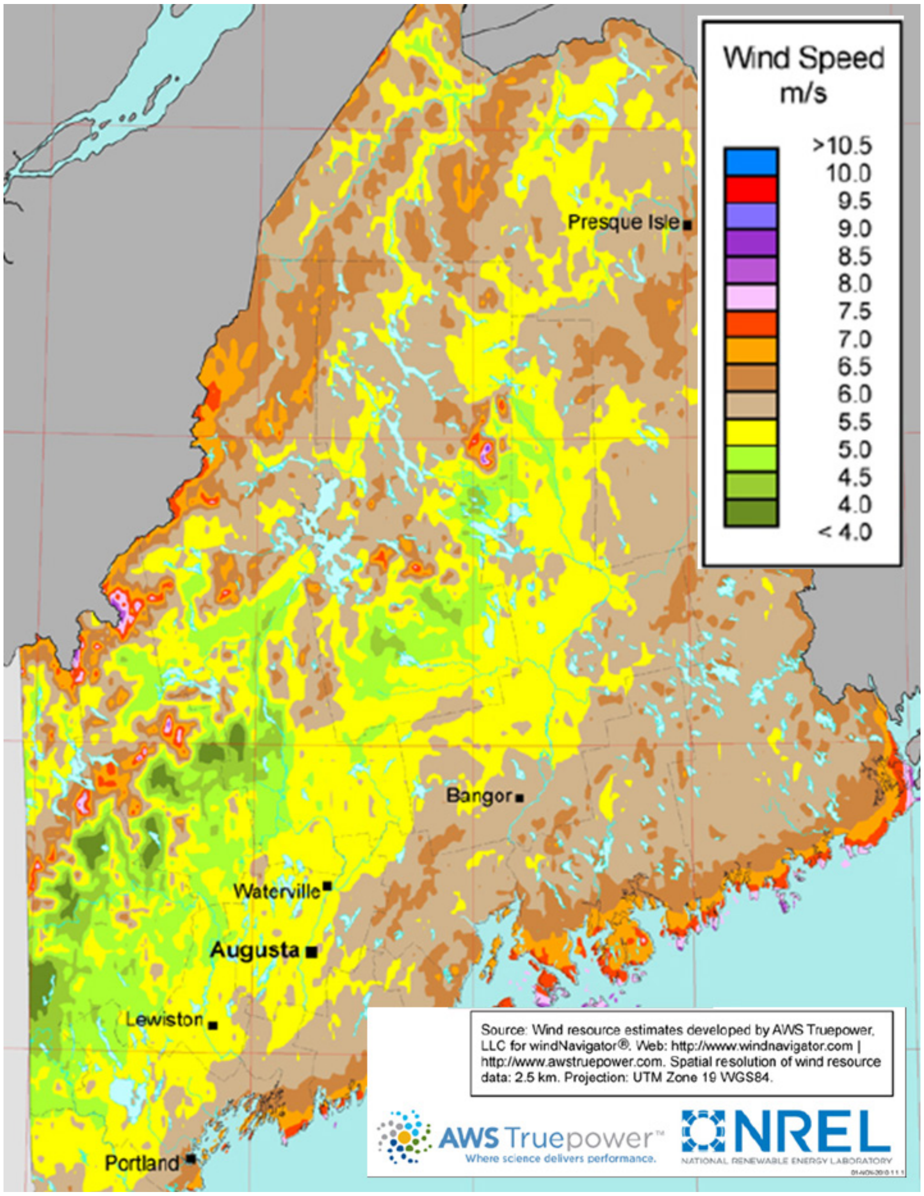
Installed Capacity	MW	192
Qualified Capacity	%	100%
Capital Costs (Installed)	$/kW	1,652
ATWACC	%	7.2%
Revenue Escalation Rate	%/yr	2.25%
Depreciation Schedule		15yr MACRS
Gross CONE	*$/kW-mo*	*16.13*
Capital Costs	$/kW-mo	18.09
Fixed O&M	$/kW-mo	2.65
Depreciation Tax Shield	$/kW-mo	-4.61
Revenue Offsets	*$/kW-mo*	*2.71*
E&AS Margins	$/kW-mo	2.71
Net CONE (Installed)	*$/kW-mo*	*13.42*
Net CONE (Qualified)	*$/kW-mo*	*13.42*
ORTP	**$/kW-mo**	**13.424**

V. Onshore Wind ORTP

A. Technical Specifications

To establish technical specifications for the reference onshore wind farm, we reviewed the most recent and projected projects in Maine, where most of New England's wind farms are being developed. Figure 6 shows the relative wind speeds in Maine. Although there is significant generation in both western Maine and northern Maine, we selected western Maine due to the proximity to transmission lines and the robustness of the network in that area, consistent with our approach for the CCGT and CT plants.

Figure 6
Maine Average Wind Speeds Map



The capacity of the reference wind farm is based on the size of wind farms being built in New England. Table 25 shows the total capacity of wind farms under construction or recently built in ISO-NE region since 2010. The reference wind farm's nameplate capacity is assumed to be 60 MW, at the upper end of the recent projects.

Table 25
ISO-NE Wind Farms Under Construction or Built Since 2010

	<20 (MW)	20-40 (MW)	40-60 (MW)	60-80 (MW)	80-100 (MW)	>100 (MW)
ISO-NE	104	128	159	129	99	0

Source: Ventyx, 2013.

Several wind turbine models were considered for the reference plant. Costs do not appear to differ materially among manufacturers. However, based on the location and the reported performance of the turbines, S&L determined that the most likely wind turbine to be used for this location is the GE 1.6-100, with a rating of 1.62 MW. Thus the assumed 60 MW reference wind farm would consist of 37 turbines.

To estimate the capacity factor for the reference wind farm, we considered that wind turbine technology has been improving. The new turbines available today (including the 100 meter GE 1.6-100) have larger rotor diameters and are able to achieve higher capacity factors than machines used in the recent past, with the improvements coming especially at the lower wind speeds. The average capacity factor of proposed new wind farms currently undergoing asset-specific reviews by the IMM, which include verification by a third party consultant, is 35%. We also received input from stakeholders and advice from our engineering consultant, S&L. Based on these sources, we assumed a reference capacity factor of 35%.

In addition, we compared the assumed capacity factor of 35% to historical output from existing wind farms. Based on the generation data provided by ISO-NE, we identified ten plants with nameplate capacity greater than fifteen megawatts and that had been in operation for more than six months as of January 1, 2013. Among those ten plants, only four had a capacity factor greater than 25%, which we considered the relevant population for defining a competitive ORTP. Their average capacity factor is 31%. We believe the upward adjustment to 35% for new facilities is reasonable based on the improved technology available today. Some stakeholders raised concerns about whether such a capacity factor is consistent with our cost assumptions, and it is. As discussed above, the turbine assumed for cost purposes is a GE 1.6-100, which has a 100 meter rotor diameter. Smaller turbines would be less efficient and would cost less.

We used the same four wind farms as the basis for estimating qualified capacity (and energy revenues). Because wind is intermittent, qualified capacity is less than nameplate capacity, and resources are paid according to their individual qualified capabilities for summer and winter.[57] The qualified capacity value for the reference onshore wind technology was assumed to be the average seasonal claimed capability of the four sample wind farms for the years in which they

[57] ISO New England Inc., Transmission, Markets, & Services Tariff, Section III–Market Rule 1, Section III.13.2.7.6 http://www.iso-ne.com/regulatory/tariff/sect_3/index.html.

were in operation, which was 25% over the past three years.[58] (We did not make any adjustments for the new technology as we did for capacity factor, since the larger turbine's effect on peak output is already accounted for in the nameplate capacity.) Table 26 shows the winter, summer, and seasonally-weighted values for each Seasonal Claimed Capability (SCC) Monthly Report and the calculated average qualified capacity for onshore wind.[59]

Table 26
Seasonal Claimed Capability Values for Onshore Wind

SCC Monthly Report	Summer	Winter	Seasonally-Weighted
August 2011	14%	33%	27%
August 2012	14%	35%	28%
August 2013	10%	27%	21%
Average	13%	31%	**25%**

Source: ISO-NE, 2013b.

The specifications for the onshore wind reference technology are summarized in Table 27.

Table 27
Technical Specifications
Reference Onshore Wind Farm

Unit Specifications	On-Shore Wind
Turbine Model	GE 1.6-100
Primary Fuel	Wind
Configuration	37 x 1.62 MW
Net Plant Capacity (MW)	60
Capacity Factor	35%
Qualified Capacity	25%
Interconnection	115 kV
Plot Size (acres)	3,840
Location	Western ME

58 ISO-NE, 2013b.

59 As the newer wind turbines are primarily able to increase performance at lower wind speeds, we have not made an adjustment to the qualified capacity value due to the change in turbine technology.

B. Capital Costs

S&L provided capital cost estimates for the reference wind farm, as summarized in Table 28 below and explained further in the Technical Appendix. S&L did not provide electric interconnection costs, which Brattle estimated as explained further below. We estimate that the overnight cost for the wind farm will be $184 million in 2018 dollars, or $3,063/kW.

Table 28
Overnight Capital Costs
Reference Onshore Wind Farm

	2013 Overnight Costs *(2013 $)*	2013 Overnight Costs *(2013 $/kW)*	2018 Overnight Costs *(2018 $/kW)*
EPC Costs			
Equipment			
Wind Turbines	$77,922,000	$1,300	$1,482
Other Equipment	$5,994,000	$100	$114
Construction Labor	$7,193,000	$120	$144
Other Labor	$1,798,000	$30	$36
Materials	$6,593,000	$110	$125
Sales Tax	$4,525,000	$75	$86
EPC Contractor Fee	$10,403,000	$174	$199
EPC Contingency	$11,443,000	$191	$219
Total EPC Costs	**$125,871,000**	**$2,100**	**$2,405**
Non-EPC Costs			
Owner's Costs (Services)	$8,811,000	$147	$168
Electrical Interconnection	$19,000,000	$317	$361
Working Capital	$1,259,000	$21	$24
Owner's Contingency	$2,326,000	$39	$44
Financing Fees	$3,145,000	$52	$60
Total Non-EPC Costs	**$34,541,000**	**$576**	**$658**
Overnight Capital Costs ($)	**$160,412,000**	**$2,676**	**$3,063**

Electrical interconnection costs are based on our review of system impact studies from new and planned projects and assume no network upgrades are needed. We assumed a 10-mile direct assignment transmission line would be necessary based on the assumed location, the transmission system in the area, and interconnection system studies of wind farms similar to the reference wind farm. For the unit cost of the transmission line, we estimated the cost per mile of the line based on cost estimates for six 115 kV transmission lines that are a part of the Maine Power Reliability Program.[60] The substation equipment costs were developed from the ISO-NE

[60] Central Maine Power Company, 2009

Transmission Project Listing.[61] Table 29 shows the assumed equipment required for the direct assignment facilities and the assumed costs. The estimated electrical interconnection cost for the reference wind farm is $19 million in 2013 dollars, or $317/kW.

Table 29
Electrical Interconnection Equipment and Costs
Reference Wind Farm

Component	***Quantity*** *(#)*	***Unit Price*** *(m$)*	***Cost*** *(m$)*
115 kV Transmission Line (miles)	10	1.7	$17.0
Substation Equipment (breakers)	2	1.0	$2.0
Total (m$)			**$19.0**
Total ($/kW)			**$317.0**

Notes: All costs are shown in 2013 dollars.

C. FIXED O&M COSTS

S&L estimated fixed O&M costs based on its experience and the following assumptions specific to the technical specifications of the reference onshore wind farm.

The plant owner leases 3,840 acres at a market rate of $200/acre-year, based on leasing costs representative of rural land costs in Western Maine. The annual leasing cost for the wind farm is $768,000 per year in 2013 dollars.

The property taxes of 0.50% of the overnight capital cost per year were estimated from a sample of independent power projects in New England that have entered into agreements for payments in lieu of taxes (PILOT) with local jurisdictions. Based on the rate of 0.50%, the property tax for the wind farm was estimated at $806,000 per year in 2013 dollars.

We calculated insurance costs at 0.3% of the overnight capital costs, based on a sample of independent power projects recently under development in the Northeastern US and discussions with a project developer. Annual insurance for the wind farm was estimated at $481,000 in 2013 dollars.

From these assumptions, we calculated for the wind farm a fixed O&M cost of $69.27/kW-yr in 2013 dollars, escalated to $79.40/kW-yr in 2018 dollars. Table 22 summarizes the fixed O&M costs for the wind farm.

61 ISO-NE, 2013c.

Table 30
Fixed Operating and Maintenance Costs
Reference Wind Farm

	2013 Costs *(2013$)*	2018 Costs *(2018$)*
Fixed O&M		
Labor	$599,000	$720,000
Materials and Contract Services	$599,000	$683,000
Administrative and General	$899,000	$1,025,000
Site Leasing Costs	$768,000	$858,000
Property Taxes	$806,000	$922,000
Insurance	$481,000	$551,000
Total Fixed O&M ($)	**$4,152,000**	**$4,759,000**
Total Fixed O&M ($/kW-year)	**$69.27**	**$79.40**

A. Revenue Offsets

The revenue offsets for the reference wind farm derive from energy margins and from RECs (In our analysis we have also included the value of the production tax credit in calculating the onshore wind ORTP, but have accounted for it in the CONE calculation.) We obtained historical actual revenues earned by the four wind farms with similar characteristics to our reference plant from ISO-NE. Since we assumed no variable O&M costs, we considered their energy margins to be equal to their revenues. As Table 31 shows, the 2010 – 2012 average energy margins for these representative wind farms was $9.47/kW-mo, and the projected 2018/19 margin is estimated to be $13.23/kW-mo using the forward projections explained in the Methodology section. Next, to capture the effect of technological improvements since the sample projects were built, we grossed up the energy margins by the increase in capacity factor of our reference wind farm compared with the historical sample. The average capacity factor of the representative plants is 31%, while that of the reference wind farm is 35%, resulting in a projected 2018/2019 E&AS margin of $14.94/kW-mo.

Table 31
Historical and Projected Energy Margins for Wind Farms

	Historical Actuals			**Future Projections**						
($/kW-mo)	2010	2011	2012	2013	2014	2015	2016	2017	2018	**2018/19**
Representative Wind Plants	$10.97	$9.94	$7.49	$12.38	$11.56	$12.02	$12.34	$12.64	$12.99	**$13.23**
Reference Wind Plant	n.a.	n.a.	n.a.	$13.98	$13.06	$13.57	$13.94	$14.27	$14.66	**$14.94**

Notes: All values are shown in nominal dollars.

As discussed in the Methodology section, we estimated that 2018/2019 RECs based on a PPA, to align with tariff requirements, would be priced at $49.3/MWh. With the assumed capacity factor, the revenue offset from RECs is $12.60/kW-mo.

B. ORTP Calculation

Based on the cost estimates, financial assumptions, and projected revenues escalation rate, the first year revenue requirement, or Gross CONE, for the wind farm such that the NPV equals zero is $23.89/kW-mo. The components of Gross CONE are shown in Table 32.

The first year revenue offset derived from E&AS margins and REC revenues is $27.53/kW-mo. The Net CONE value based on the installed capacity for the wind farm is estimated to be $-3.64/kW-mo. As the Net CONE value is less than zero, we recommend the ORTP value for Onshore Wind to be $0.000/ kW-mo.

Table 32
Onshore Wind ORTP Calculation

Installed Capacity	MW	60
Qualified Capacity	%	25%
Capital Costs (Installed)	$/kW	3,263
Capacity Factor	%	35%
ATWACC	%	7.2%
Revenue Escalation Rate	%/yr	2.25%
Depreciation Schedule		5yr MACRS
Gross CONE	*$/kW-mo*	*23.89*
Capital Costs	$/kW-mo	35.72
Fixed O&M	$/kW-mo	6.62
Depreciation Tax Shield	$/kW-mo	-12.22
Tax Credits	$/kW-mo	-6.22
Revenue Offsets	*$/kW-mo*	*27.53*
E&AS Margins	$/kW-mo	14.94
REC Revenue	$/kW-mo	12.60
Net CONE (Installed)	*$/kW-mo*	*-3.64*
Net CONE (Qualified)	*$/kW-mo*	*-14.55*
ORTP	**$/kW-mo**	**0.000**

VI. Energy Efficiency ORTP

A. Technical Specifications

ISO-NE allows energy efficiency (EE) providers to offer peak-load reductions into FCM as a demand resource. The providers are generally the electric utilities that administer EE programs, and they offer their programs into FCM as an aggregated bundle. We determined the reference specifications for such an EE bundle through a review of the programs in all of the New England states.

In total, we identified fifty-five EE programs. We chose to remove six programs that are specifically designed for low income customers, as low income programs were not required to pass the cost-benefit tests because they serve other policy objectives.[62] Table 33 shows the programs we selected to include in the reference EE bundle.

Table 33
State Programs Included in Reference EE Bundle

Connecticut	Massachusetts	Maine	New Hampshire	Rhode Island	Vermont
Residential Consumer Products	Resid'tl. New Constrct. & Renovations	Residential Lighting	ENERGY STAR Lighting	Large Commercial New Construction	Residential New Construction
Residential New Construction	Residential Heating and Water Heating	Residential Appliances	ENERGY STAR Homes	Large Commercial Retrofit	Residential Efficient Products
Home Energy Solutions	Multifamily Retrofit	Business Incentive Program	Home Energy Solutions	Small Business Direct Install	Business New Construction
C&I Lost Opportunity	MassSAVE	Large Customer	ENERGY STAR Appliances	Residential New Construction	Business Existing Facilities
C&I Large Retrofit	O Power		New Equipment & Construction	ENERGY STAR HVAC	Residential Existing Homes
C&I Small Business	ENERGY STAR Lighting		Large C&I Retrofit	Energy*Wise*	
	ENERGY STAR Appliances		Small Business Energy Solutions	ENERGY STAR Lighting	
	C&I New Constrct. & Major Renovations			ENERGY STAR Appliances	
	C&I Large Retrofit				
	C&I Small Retrofit				

Sources: Connecticut: CL&P, *et al*., 2011. Massachusetts: National Grid, *et al*., 2009. Maine: Efficiency Maine, 2013. New Hampshire: Granite State, *et al.*, 2010. Rhode Island: National Grid, 2012.Vermont: Efficiency Vermont, 2013.

In aggregate, the programs included in the reference EE bundle have the capability to provide 395 MW of capacity during the summer peak hours at the retail meter and, accounting for the avoided losses over the transmission and distribution networks, 427 MW of capacity at the

62 The six programs not include are New Hampshire Home Energy Assistance, Connecticut HES Income Eligible for both CL&P and UI, Massachusetts Low Income Residential New Construction and Low Income Retrofit, and Rhode Island Single Family Low Income Services.

generator bus bar. The life of measures within each program is assumed to be 11 years, consistent with the average of actual programs.

For presentation purposes, we scaled this set of programs down to a 1 MW bundle representative of an EE bid to the FCA. We calculated based on the state program data that a bundle of this size would be expected to provide 4,212 megawatt-hours of annual energy savings. The technical specifications of the EE bundle are shown in Table 34.

Table 34
Technical Specifications
Reference Energy Efficiency Bundle

Unit Specifications	Energy Efficiency
Capacity (MW at Generator Bus Bar)	1
Annual Energy Savings (MWh)	4,212
Program Life (years)	11

B. Capital Costs

To estimate the capital costs of EE programs, we relied on the 2012-year budgets and expenditures for the state programs identified as a part of the EE bundle. We calculated the cost per kilowatt using both the program costs and the customer out-of-pocket costs. As shown in Table 35, the capital cost of the reference EE bundle is $2,571/kW in 2018 dollars.

Table 35
Program Costs and Capacities
Reference EE Bundle

Energy Efficiency	2013 Operating Costs *(2013 $)*	2013 Operating Costs *(2013 $/kW)*	2018 Operating Costs *(2018 $/kW)*
Capacity Value (MW)			
At Meter	395	395	395
At Generator Bus Bar	427	427	427
Operating Costs ($)			
Labor & Services	90,419,000	212	242
Materials & Supplies	102,000	0	0
Incentives	485,897,000	1,138	1,301
Marketing, A&G, Other	46,660,000	109	125
Customer Costs	316,352,000	741	847
M&V	20,717,000	49	55
Total Operating Costs	**960,147,000**	**2,250**	**2,571**

C. Revenue Offsets

Revenue offsets for the reference EE bundle include both the value of wholesale energy saved and the value of avoiding or delaying transmission and distribution (T&D) investments.

For energy savings, we calculated the historical average load-weighted Mass Hub electricity prices from 2010 to 2012. We adjusted the historical average prices by Mass Hub electricity futures, similar to the approach taken for generation technologies, such that the projected 2018/19 load-weighted electricity price is $62.63/MWh. Based on this electricity price, the energy savings of the reference EE bundle is $263,798 in 2018 dollars, or $21.99/kW-mo.

For T&D savings, we adopted the value used by Connecticut utility companies for avoided T&D costs in their benefit-cost tests and escalated the value by inflation to 2018/19. The estimated T&D savings for the EE bundle is $40.55/kW-yr in 2018 dollars. [63]

D. ORTP Calculation

Based on the cost estimates, the Gross CONE for the EE bundle such that the NPV equals zero is $24.39/kW-mo. The first year revenue offset derived from energy and T&D savings is $25.37/kW-mo. The Net CONE value for the EE bundle is therefore estimated to be -$0.97/kW-mo. As the resulting Net CONE value is negative, we recommend the ORTP value for EE to be $0.000/ kW-mo. as shown in Table 36.

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63 CL&P, *et al.*, 2012, p. 307.

Table 36
Energy Efficiency Program ORTP Calculation

Installed Capacity	MW	1
Qualified Capacity	%	100%
Capital Costs (Installed)	$/kW	2,571
ATWACC	%	7.2%
Annual Energy Savings	MWh	4,212
Energy Benefit	$/MWh	62.63
Avoided T&D Costs	$/kW-yr	40.55
Gross CONE	*$/kW-mo*	*24.39*
Capital Costs	$/kW-mo	24.39
Fixed O&M	$/kW-mo	0.00
Revenue Offsets	*$/kW-mo*	*25.37*
Energy Savings	$/kW-mo	21.99
T&D Savings	$/kW-mo	3.38
Net CONE	*$/kW-mo*	*-0.97*
ORTP	**$/kW-mo**	**0.000**

VII. Demand Response ORTPs

A. Technical Specifications

Demand response resources are more varied than generation technologies, which tend to use standard equipment in standard configurations. Some demand response is based on load reductions by large end-users, some by smaller end-users. Some DR resources already have most of the enabling equipment in place and others do not. And some involve interrupting higher-value and more time-varying valued loads than others. As a result, competitive offers could reasonably vary over a large range.

Recognizing this range, we defined two separate DR classes for calculating ORTP values: Large DR and Mass Market DR. We did not specifically assess the costs of demand response with existing or new distributed generation measures, such as combined heat and power, combustion turbines or solar. Given the likely range in costs and types of distributed generation projects, along with the limited available detailed data required to determine the appropriate ORTP, the IMM advised that the ORTP for such resources should be based on the underlying technology.

We assumed the following characteristics for each of the classes analyzed.

- **Large DR** is considered to be a medium-size commercial facility, such as an office building, hospital, or college, with 2 MW of peak load and the ability to reduce its load by

25%. The resulting load reduction capacity is assumed to be 500 kW. We assumed the customer is already using existing control technologies, such as an energy management system (EMS), to implement load reductions. This favorable assumption about existing equipment is consistent with the principle of identifying the low end of competitive offers, as discussed in the Introduction.

- **Mass Market DR** is considered to be an asset developed through large-scale state or utility programs targeting residential or small commercial customers that control specific end-uses (*e.g.*, air conditioning or water heating) and can provide 1 kW of load reduction. The customer is assumed to already have automatic meter reading equipment.

B. Capital Costs

Our cost estimates for both types of DR derive from interviews with providers active in the New England market, as described in the Methodology section. We found a surprisingly high degree of consistency among responses from those interviewed.

1. Large DR

For Large DR, the interviews revealed that there are three incremental cost components for implementing a new DR resource: metering and communication equipment costs (assuming an EMS is in place), customer incentives (often referred to as "revenue sharing"), and the sales representative commission. Network operating center costs, such as dispatch, data management and verification, IT costs, payments and settlements, and administrative, were considered in our analysis to be the fixed costs of operating a DR aggregation business, not costs that increase as additional resources are developed, and thus were not used to calculate the Large DR ORTP.

Based on the interviews, the equipment cost for a 500 kW ideal customer is estimated to be $3,500, as shown in Table 37. To calculate the first year capacity revenues for calculating an ORTP, we amortized capital costs across the contract life of each asset. Based on our interviews with DR aggregators, new Large DR resources are currently most likely to be signed to three year contracts. We amortized the costs based on the ATWACC calculated in Section II.C.2 and assuming that future costs will increase at inflation.

Table 37
Capital Cost Estimates
Reference Large DR Asset

Incremental Cost Components	Cost ($)
Equipment Costs	3,500
Customer Incentive	5,460
Sales Rep. Commission	190

Large DR providers generally provide customer incentive payments as a percentage of the clearing price, with 50 to 80% going to the customer, more often at the high end of that range. We chose to use 70% in our analysis. Thus, customers participating in recent FCAs would typically receive 70% of the FCA clearing price of $3.15/kW-mo, or about $2.20/kW-mo. It can be inferred that participating customers must have a reservation price for being interruptible at that level or lower.

We assumed a reservation price of only $0.91/kW-mo based on the following observation: many DR providers have held on to their capacity supply obligations (CSOs) in spite of a low-cost opportunity to shed their CSOs in lower-priced reconfiguration auctions, where the recent clearing price was only $1.30/kW-mo. If they had a higher reservation price of $2.20/kW-mo, it would be economically rational for them and their curtailment service provider to arrange to shed the CSO, paying other suppliers to take on the obligation. Assuming the same 70% sharing percentage would apply to such a transaction, the fact that many customers retain their obligation suggests a reservation price of $0.91 or below.

Regarding the sales commission, the interviews indicated a range of 0.5 to 2.0% of the FCA clearing price. We assumed 1.0% for the purposes of the ORTP calculation.

2. Mass Market DR

For Mass Market DR, we used information obtained through our interviews for identifying the cost components. We used information from both the interviews and publicly available data sources for the costs. Similar to Large DR, three capital cost components were identified: equipment costs, initial customer incentives, and marketing, sales and recruitment (MS&R) costs. For the AC load control equipment required to respond to utility signals, providers indicated a cost range of $100 – 150, and we assumed the middle of the range, $125. Customer incentives for mass market DR are direct payments to the participating household and include both a one-time sign-up incentive as well as an annual participation incentive in every year. We received input that the customer incentive generally ranges from $30 – 70, and we assumed $40. The initial customer incentive is then $40 and the annual customer incentive is also $40. As for MS&R costs, providers indicated a range of $15 – 75, and we assumed $40 as it is on the lower end of the range.

We identified two additional annual costs required to maintain a Mass Market DR resource. Annual costs for operating and maintaining the resource are $10 per year, and updates to the software and communications systems are also $10 per year.

A summary of the capital and annual costs for the Mass Market DR asset are shown in Table 38. To calculate the first year capacity revenues required to enter a bid into the FCA, we amortized capital costs across the contract life of each asset. We have used the most common length of state and utility programs, ten years. We amortized the costs based on the ATWACC calculated in Section II and assuming that future costs will increase at inflation.

Table 38
Capital and Annual Cost Estimates
Reference Mass Market DR

Incremental Cost Components	Cost
Capital Costs ($)	**205**
Equipment Costs	125
Initial Customer Incentives	40
Mktg, Sales & Recruitment	40
Annual Costs ($/yr)	**60**
Annual Customer Incentives	40
O&M Costs	10
Software/Communication	10

C. ORTP Calculation

Based on the cost estimates and financial assumptions, the first year incremental cost of new entry for Large DR is $1.15/kW-mo. The components of our analysis are shown in Table 39. We recommend the ORTP value for Large DR to be $1.145/kW-mo.

Table 39
Large DR ORTP Calculation

Assumptions		
Demand Reduction	kW	500
Contract Life	years	3
ATWACC	%	7.2%
Customer Incentive	%	70%
Sales Commission	%	1%
Capacity Clearing Price	$/kW-mo	3.15
Reconfiguration Clearing Price	$/kW-mo	1.30
Equipment Costs	$	3,500
Incremental Costs		
Equipment Costs	$/kW-mo	0.20
Customer Incentive	$/kW-mo	0.91
Sales Rep. Commission	$/kW-mo	0.03
Total Incremental Costs	$/kW-mo	*1.15*
ORTP	$/kW-mo	**1.145**

Based on the cost estimates and financial assumptions, the first year incremental cost of new entry for Mass Market DR is $7.09/kW-mo. The components of our analysis are shown in Table 40. We recommend the ORTP values for Mass Market DR to be $7.094/kW-mo.

Table 40
Mass Market DR ORTP Calculation

Assumptions		
Demand Reduction	kW	1
Contract Life	years	10
ATWACC	%	7.2%
Total Installation Costs	$	$205
Mktg, Sales & Recruitment	$	$40
Equipment Costs	$	$125
Initial Customer Incentives	$	$40
Annual Customer Incentives	$/yr	$40
O&M Costs	$/yr	$10
Software/Communication	$/yr	$10
Incremental Costs		
Installation Costs	$/kW-mo	2.09
Annual Customer Incentives	$/kW-mo	3.33
O&M Costs	$/kW-mo	0.83
Software/Communication	$/kW-mo	0.83
Total Incremental Costs	*$/kW-mo*	*7.09*
ORTP	$/kW-mo	**7.094**

VIII. Annual Updates

The market rules provide that ORTPs must be calculated every third year and should be escalated in year 2 and 3 before being re-calculated for the following year. To estimate the ORTP values in FCA 10 and 11, ISO-NE will escalate the cost components and revenue offsets developed for FCA 9 according to the indices below.

A. Indices for Capital and Fixed O&M Costs

As different cost items are expected to rise at different rates, we proposed cost indices appropriate for each cost component, so that future ORTP values can be formulaically derived and provide relatively accurate capital costs and fixed O&M costs. As shown in Table 41 below, we relied on publicly available indices such as the Producer Price Index (PPI) and the Quarterly Census of Employment and Wages (QCEW) published by the Bureau of Labor Statistics. The PPI indices measure the average change over time in the selling prices received by domestic producers for their outputs, and therefore should reflect the increase/decrease in capital investment and O&M costs for a different commercial online year.[64] The QCEW indices are developed from a quarterly

64 BLS, 2013a.

count of employment and wages reported by employers covering 98% of U.S. jobs, available at the county, state and national levels by industry.[65]

As of the date when our estimates for FCA9 were developed, most indices were available through mid-2013. When ISO-NE updates ORTPs for the upcoming FCAs, indices covering the most recent 12 months as of the update date will be compared against the annual average from mid-2012 through mid-2013 to derive the appreciate escalation rates. The full description of each index is available in the 2013 ORTP Capital Budgeting Model submitted with this report.

Table 41
Indices Applied in Various Cost Components

Cost Component	Index
Capital Costs	
Gas Turbines	BLS-PPI "Turbines and Turbine Generator Sets"
Steam Turbines	BLS-PPI "Turbines and Turbine Generator Sets"
Wind Turbines	Bloomberg Wind Turbine Price Index
Other Equipment	BLS-PPI "General Purpose Machinery and Equipment"
Construction Labor	BLS "Quarterly Census of Employment and Wages" 2371 Utility System Construction Average Annual Pay: - Combustion Turbine and Combined Cycle Gas Turbine costs to be indexed to values corresponding to the location of Hampden County, Massachusetts - On-shore Wind costs to be indexed to values corresponding to the location of Cumberland County, Maine
Other Labor	BLS "Quarterly Census of Employment and Wages" 2211 Power Generation and Supply Average Annual Pay: - Combustion Turbine and Combined Cycle Gas Turbine costs to be indexed to values corresponding to the location of Hampden County, Massachusetts - On-shore Wind costs to be indexed to values corresponding to the location of Cumberland County, Maine
Materials	BLS-PPI "Materials and Components for Construction"
Electric Interconnection	BLS-PPI "Electric Power Transmission, Control, and Distribution"
Gas Interconnection	BLS-PPI "Natural Gas Distribution: Delivered to ultimate consumers for the account of others (transportation only)"
Fuel Inventories	Federal Reserve Bank of St. Louis "Gross Domestic Product: Implicit Price Deflator (GDPDEF)"
Fixed O&M Costs	
Labor, Administrative and General	BLS "Quarterly Census of Employment and Wages" 2211 Power Generation and Supply Average Annual Pay: - Combustion Turbine and Combined Cycle Gas Turbine costs to be indexed to values corresponding to the location of Hampden County, Massachusetts - On-shore Wind costs to be indexed to values corresponding to the location of Cumberland County, Maine
Materials and Contract Services	BLS-PPI "Materials and Components for Construction"
Site Leasing Costs	Federal Reserve Bank of St. Louis "Gross Domestic Product: Implicit Price Deflator (GDPDEF)"

Sources and Notes: Bureau of Labor Statistics ("BLS") Producer Price Index ("PPI") from BLS, 2013a and Quarterly Census of Employment and Wages from BLS, 2013b; Gross Domestic Product Deflator from St. Louis Fed, 2013.

65 BLS, 2013b.

B. Updates on Revenue Offsets

As discussed in the Methodology section, we forecasted 2018/19 Mass Hub electricity prices based on traded gas futures and implied market heat rates in 2013/14. For ISO-NE to update the E&AS margins for FCA 10 and 11, Henry Hub gas futures will need to be updated through the commitment periods and the Algonquin City-Gates and Mass Hub On-Peak prices updated for the next twelve months that information is available.

For updating REC values, the most up to date trading data for Massachusetts Class I RECs should be identified and escalated to the commitment period accordingly.

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Appendix A: Demand Response Interview Summary

To develop an ORTP value for Demand Response resource types, we conducted interviews with demand response providers to identify the resource types that are likely to be competitive entrants and to quantify the costs associated with those resource types. This approach was reviewed at the initial NEPOOL meeting on the 2013 ORTP study with all interested demand response market participants requested to be interviewed if they wished.

We conducted interviews with five demand response aggregators in New England, including several of the largest aggregators in the industry. The interviews were confidential to allow for an open discussion.

The interviews included the following questions:

1. Can you please define an ideal DR customer in terms of size, sector, load reduction, etc.?
2. What are the main cost components associated with a new ideal DR customers? We have identified the following cost categories, are there any others we are missing?
    a. Marketing, Sales, and Recruitment (incremental cost)
    b. Equipment Set-up (incremental cost)
    c. Revenue Sharing (incremental cost)
    d. Network operating center (allocated cost)
3. What do you think the typical costs are for an ideal customer? (We understand that this information might be confidential. We appreciate any indication or ranges you can provide us with.)
4. Do you have any reservations with the way we propose to calculate the ORTP for DR as outlined in The Brattle Group's presentation on June 4, 2013 at the stakeholder meeting?

The information collected for the Mass Market demand response resource was supplemented with cost data from Xcel Energy Saver's Switch program, which is a mature mass market direct load control program located in Colorado.

The following tables summarize the range of information received from the interviewees relevant to the analysis and the values utilized in the ORTP analysis.

Table A-42
Mass Market Asset Cost Assumptions

Mass Market	Units	Suggested Range	Values Used in Analysis
Demand Reduction	kW	0.75 - 1.25	1
Contract Life	years	10	10
Mktg, Sales & Recruitment	$	$15 - 75	$40
Equipment Costs	$	$100 - 150	$125
Initial Customer Incentives	$	$30 -70	$40
Annual Customer Incentives	$/yr	$30 -70	$40
O&M Costs	$/yr	$2 - 45	$10
Software/Communication	$/yr	$5 - 10	$10

Table A-43
Large C&I Asset Cost Assumptions

Large C&I	Units	Suggested Range	Values Used in Analysis
Demand Reduction	kW	200 - 1,000	500
Contract Life	years	3	3
Customer Incentive	%	50 - 80%	70%
Sales Commission	%	0.5 - 2.0%	1%
Equipment Costs	$	$3,000 - 4,000	$3,500

Appendix B: ISO New England Offer Review Trigger Price Technical Appendix

ISO New England
Offer Review Trigger Price
Technical Appendix

Prepared for
The Brattle Group, Inc.

SL-012079
Project 13122-001
December 2013

The Brattle Group

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ISO New England
Offer Review Trigger Price
Technical Appendix

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Technical Appendix

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LEGAL NOTICE

This report ("Deliverable") was prepared by Sargent & Lundy, L.L.C. ("S&L"), expressly for the Brattle Group, Inc. in accordance with Contract SA-29416, dated April 29, 2013. This Deliverable was prepared using the degree of skill and care ordinarily exercised by engineers practicing under similar circumstances. Client acknowledges (1) S&L prepared this Deliverable subject to the particular scope limitations, budgetary and time constraints, and business objectives of the Client; (2) information and data provided by others may not have been independently verified by S&L; and (3) the information and data contained in this Deliverable are time sensitive and changes in the data, applicable codes, standards, and acceptable engineering practices may invalidate the findings of this Deliverable. Any use or reliance upon this Deliverable by third parties shall be at their sole risk.

ISO New England
Offer Review Trigger Price
Technical Appendix

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TABLES

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ACRONYMS AND ABBREVIATIONS

Term	Definition or Clarification
BLS	Bureau of Labor Statistics
CCGT	Combined cycle gas turbine
CT	Combustion turbine
DB	Dry bulb
EPC	Engineer, procure, and construct
FCA	Forward Capacity Auction
GDPD	Gross Domestic Product Deflator
GE	General Electric
HHV	Higher heating value
HRSG	Heat recovery steam generator
ICAP	Installed capacity
ISO-NE	Independent System Operator – New England
mmBtu	Millions of Btu
MWh	Megawatt-hour
NREL	National Renewable Energy Laboratory
O&M	Operation and maintenance
ORTP	Offer Review Trigger Price
PPI	Producer Price Index
PV	Photovoltaic
QCEW	Quarterly Census of Employment and Wages
RH	Relative humidity
S&L	Sargent & Lundy, L.L.C.

ACRONYMS AND ABBREVIATIONS (cont.)

Term	Definition or Clarification
SCR	Selective catalytic reduction
SNCR	Selective non-catalytic reduction
SREC	Solar Renewable Energy Credit
ULSD	Ultra low sulfur diesel fuel
WB	Wet bulb

EXECUTIVE SUMMARY

Sargent & Lundy, L.L.C. (S&L) is a subcontractor to The Brattle Group for the 2013 Offer Review Trigger Price (ORTP) Study for ISO New England (ISO-NE). The purpose of the study is to determine the underlying cost and revenue data for capacity resource types to be used as inputs into ISO-NE's capital budgeting model to calculate ORTP for the Forward Capacity Auction (FCA) to be conducted in February 2015 through the FCA occurring in February 2017. As part of the study, a methodology and data sources were recommended to escalate the ORTPs in years 2 and 3.

Sargent & Lundy's scope of work was to estimate the capital costs, including direct, indirect, and owner's costs, fixed and variable operation and maintenance (O&M) costs, and performance estimates for the generating technologies considered in the ORTP study (simple cycle combustion turbine (CT), combined cycle gas turbine (CCGT), on-shore wind, solar photovoltaic (PV), and biomass firing in a fluidized bed boiler), each at one location within the ISO-NE region. Costs and performance for each technology were estimated on the basis of a single representative configuration.

Based on the factors discussed herein, the selected configurations, site characteristics, and performance for each representative technology are summarized below in Table ES-1, Table ES-2, and Table ES-3.

Table ES-1 — Technology Configuration Summary

Unit Specifications	Combustion Turbine	Combined Cycle Gas Turbine	On-Shore Wind	Solar PV	Biomass
Turbine Model/PV Module Type	GE LMS100 PA	Siemens SGT6-5000F(5)	GE 1.6-100	Polysilicon PV panels, Fixed Tilt, Ground Mounted	Bubbling Fluidized Bed
Primary Fuel	Natural Gas	Natural Gas	Wind	Solar	Forest Residues
Configuration	2 x 0	2 x 2 x 1	37 x 1.62 MW	20,000 x 300 W	---
Net Plant Capacity (MW)	192	730	60	6 (DC)	50
without Duct Firing (MW)	---	631	---	---	---
Cooling System	Dry	Dry	---	---	Dry
Power Augmentation	Evaporative Cooling No inlet chillers	Evaporative Cooling No inlet chillers	---	---	---
Capacity Factor	---	---	35%	14%	---

Unit Specifications	Combustion Turbine	Combined Cycle Gas Turbine	On-Shore Wind	Solar PV	Biomass
Qualified Capacity	100%	100%	25%	15%	100%
Environmental Controls	Water Injection NOx Control Pulse Inlet Air Filters SCR CO Catalyst	Dry Low NOx Burners Inlet Air Filters SCR CO Catalyst	---	---	SNCR Fabric Filter Baghouse Dry Sorbent Injection
Dual Fuel Capability	ULSD	ULSD	---	---	Biodiesel
Black Start Capability	No	No	---	---	---

Table ES-2 — Site Assumptions Summary

Unit Specifications	Combustion Turbine	Combined Cycle Gas Turbine	On-Shore Wind	Solar PV	Biomass
On-Site Gas Compression	Yes	No	---	---	---
Interconnection	345 kV	345 kV	115 kV	13 kV	115 kV
Plot Size (acres)	10	20	3,840	40	20
Location	Hampden County, MA	Hampden County, MA	Western ME	Massachusetts	Coastal ME

Table ES-3 — Plant Performance Summary

Unit Specifications	Combustion Turbine	Combined Cycle Gas Turbine	On-Shore Wind	Solar PV	Biomass
Net Heat Rate (Btu/kWh, HHV)	9,244	7,526	---	---	13,500
without Duct Firing (Btu/kWh, HHV)	---	7,204	---	---	---
Capacity Factor	---	---	35%	14%	---

The reference year (2018) capital and O&M costs for each technology configuration and site are summarized below in Table ES-4 and Table ES-5.

Table ES-4 — Capital Cost Summary (2018 $)

Capital Costs (2018 $)	Combustion Turbine	Combined Cycle Gas Turbine	On-Shore Wind	Solar PV	Biomass
Plant Capacity (MW)	192	730	60	6	50
EPC Costs					
Equipment					
Gas Turbines	88,328,000	102,574,000	0	-	0
Boiler / HRSG / SCR	15,956,000	49,008,000	0	-	46,948,000
Condenser	0	30,658,000	0	-	10,257,000
Steam Turbines	0	41,030,000	0	-	15,956,000
Wind Turbines	0	0	88,809,000	-	0
Solar PV Modules	0	0	0	-	0
Other Equipment	33,066,000	57,092,000	6,831,000	-	32,739,000
Equipment Subtotal	137,350,000	280,362,000	95,640,000	-	105,900,000
Construction Labor	46,415,000	185,292,000	8,647,000	-	83,043,000
Other Labor	16,975,000	44,277,000	2,161,000	-	41,132,000
Materials	7,986,000	37,836,000	7,514,000	-	18,962,000
Sales Tax	9,084,000	19,887,000	5,158,000	-	6,243,000
EPC Contractor Fee	21,781,000	68,118,000	11,912,000	-	16,593,000
EPC Contingency	23,959,000	63,577,000	13,103,000	-	46,762,000
Total EPC Costs	263,550,000	699,349,000	144,135,000	(included below)	318,635,000
Non-EPC Costs					
Owner's Costs (Services)	18,449,000	48,954,000	10,089,000	-	22,304,000
Electrical Interconnection	4,559,000	18,235,000	21,655,000	-	15,956,000
Gas Interconnection	4,103,000	4,103,000	0	-	0
Emission Reduction Credits	0	0	0	-	0
Land	0	0	0	-	0
Fuel Inventories	2,684,000	7,960,000	0	-	1,032,000
Working Capital and Inventories	2,636,000	6,993,000	1,441,000	-	3,186,000
Owner's Contingency	2,594,000	6,900,000	2,655,000	-	3,398,000
Subtotal - Non-EPC Costs w/o Financing Fees	35,025,000	93,145,000	35,840,000	-	45,876,000
Financing Fees	5,972,000	15,850,000	3,600,000	-	7,290,000
Total Non-EPC Costs	40,997,000	108,995,000	39,440,000	(included below)	53,166,000
Overnight Capital Costs ($)	304,547,000	808,344,000	183,575,000	15,558,000	371,801,000
Overnight Capital Costs ($/kW)	1,583	1,108	3,063	2,593	7,436

Table ES-5 — O&M Cost Summary (2018 $)

O&M Costs (2018 $)	Combustion Turbine	Combined Cycle Gas Turbine	On-Shore Wind	Solar PV	Biomass
Fixed O&M					
Labor	1,060,000	3,532,000	720,000	65,000	2,981,000
Materials and Contract Services	351,000	4,579,000	683,000	82,000	2,632,000
Administrative and General	382,000	904,000	1,025,000	41,000	1,641,000
Site Leasing Costs	212,000	425,000	858,000	9,000	425,000
Property Taxes	2,286,000	6,066,000	922,000	78,000	2,792,000
Insurance	1,827,000	4,850,000	551,000	47,000	2,231,000
Total Fixed O&M ($)	6,118,000	20,356,000	4,759,000	322,000	12,702,000
Total Fixed O&M ($/kW-year)	31.81	27.90	79.40	53.67	254.04
Variable O&M					
Major Maintenance - Hours Based	3.26	1.49	-	-	-
Consumables, Waste Disposal, and Other VOM	2.87	1.17	-	-	3.65
Variable O&M - Hours Based ($/MWh)	6.13	2.67	0.00	0.00	3.65
Variable O&M - Starts Based ($/factored start, per turbine)	-	10,444	-	-	-

I. TECHNOLOGY ASSUMPTIONS

Reference technologies were identified which would be likely competitive entrants in the FCA, consisting of simple cycle CT, CCGT, on-shore wind, solar PV, and biomass power plants. Key design parameters were specified for each technology and were used as the basis for estimating the plant costs and performance. The design parameters include plant configuration, turbine vendor models, environmental controls, other major equipment, fuel type, backup fuel capability, site location, local labor costs, site conditions, required land area, and gas and transmission interconnection requirements. The technology assumptions were developed in conjunction with Brattle as explained in the 2013 ORTP Study in more detail.

A. COMBUSTION TURBINE - PEAKER

1. Plant Configuration and Major Equipment

Based on a review of CT plants currently under construction or built in the U.S. since 2012, the most common choice has been the GE LMS100, followed by the Siemens SGT6-5000F and the GE LM6000. Two CTs in the ISO-NE interconnection queue also use the LMS100. The LMS100 and LM6000 are aeroderivative engines which are attractive for peaking duty because of their operating efficiency and because their major maintenance intervals are hours-based rather than starts-based. Compared with the LM6000, the LMS100 has a lower $/kW cost because of its larger size and has a more efficient heat rate. The LMS100 PA model, which uses water injection for NO_X control, was selected as the reference technology. A two-unit configuration was assumed to reduce the impact of common costs on the overall plant $/kW. Other features of the assumed configuration are as follows:

- GE LMS100 PA simple cycle- nominal 103 MW
- Dual Fuel: Natural gas and ULSD (2-day inventory)
- Water injection for NO_X control
- Air-cooled intercooler
- Pulse inlet air filters
- Evaporative coolers
- Selective catalytic reduction
- CO catalyst

- No inlet chillers
- No black start capability

2. Location and Site Conditions

The CT plant site was assumed to be located in Hampden County, Massachusetts. This was representative of a location with relatively unconstrained access to gas and transmission interconnections. The characteristics of the assumed site are as follows:

- Elevation, temperature, and relative humidity were developed from Springfield, MA weather data for the following conditions:
  - 70 feet above mean sea level
  - Average winter and summer conditions
    - Average summer: 82.7°F dry bulb (DB) temperature, 68°F mean co-incident wet bulb (WB) temperature, and 47.6% relative humidity (RH)
    - Average winter: 20.7°F DB temperature, 20°F mean co-incident WB temperature, and 91.4% RH
  - 90°F DB temperature, 72°F mean co-incident WB temperature, and 91.4% RH (established by ISO-NE for use in establishing the Summer Qualified Capacity, which were used to calculate $/kW values)
- Labor cost data was based on Springfield, MA
- 10-acre site
- No adjacent generating facilities, so common facilities that might otherwise be available are included in the cost estimate (e.g., switchyard, administration building, demineralized water tanks, etc.)
- Spread footing--no pile foundations required
- Fuel gas compression to 800-900 psig as required by the LMS100
- 345-kV four-breaker ring bus
- No limit on annual operating hours per year

B. COMBINED CYCLE GAS TURBINE

1. Plant Configuration and Major Equipment

Based on a review of CCGT plants currently under construction or built in the U.S. and the ISO-NE region since 2010, the most common choice has been a 2 x 1 configuration with a total plant capacity in the 500-MW to

700-MW range. The most common gas turbine models for these plants have been the GE 7FA, Mitsubishi M501G, and Siemens SGT6-5000F.

The Siemens SGT6-5000F(5) with a 2 x 1 configuration was selected as the reference technology because of the number of recent projects using this turbine model and configuration. This is the most common configuration for CCGT plants built in the U.S. and ISO-NE since 2010. Duct firing was included to increase summer output as it is common in other New England plants such as Kleen, Mystic, and Fore River. Dry cooling was selected for the reasons described by Brattle in the 2013 ORTP Study. Other features of the assumed configuration are as follows:

- Combined cycle 2 x 2 x 1 configuration
- Siemens SGT6-5000(F) - nominal 228 MW per CT
- Dual Fuel: Natural gas and ULSD (3-day inventory)
- Dry low NO_X burners
- Inlet air filters
- Dry cooling system
- Evaporative coolers
- HRSG – three-pressure with reheat, integral deaerator
- Selective catalytic reduction
- CO catalyst
- Duct burners - constant 470 mmBtu/hr (HHV) to duct burner for approximately 100 MW of output
- Siemens condensing reheat steam turbine with down exhaust
- No inlet chillers
- No black start capability
- No additional flexibility for load following

2. Location and Site Conditions

The CCGT plant site was assumed to be located in Hampden County, Massachusetts. This was representative of a location with relatively unconstrained access to gas and transmission interconnections. The characteristics of the assumed site are as follows:

- Elevation, temperature, and relative humidity were developed from Springfield, MA, weather data for the following conditions:
  - 70 feet above mean sea level
  - Average winter and summer conditions
    - Average summer: 82.7°F dry bulb (DB) temperature, 68°F mean co-incident wet bulb (WB) temperature, and 47.6% relative humidity (RH)
    - Average winter: 20.7°F DB temperature, 20°F mean co-incident WB temperature, and 91.4% RH
  - 90°F DB temperature, 72°F mean co-incident WB temperature, and 91.4% RH (established by ISO-NE for use in establishing the Summer Qualified Capacity, which were used to calculate $/kW values)
- Labor cost data for Springfield, MA
- 20-acre site
- No adjacent generating facilities, so common facilities that might otherwise be available were included in the cost estimate (e.g., switchyard, administration building, demineralized water tanks, etc.)
- Spread footing--no pile foundations required
- No fuel gas compression required
- 345-kV five-breaker ring bus
- No limit on annual operating hours per year

C. ON-SHORE WIND

1. Plant Configuration and Major Equipment

The plant configuration for the on-shore wind plant was based on the assumed siting in Western Maine. Many areas in Western Maine have wind speeds ranging between 6.0 m/s and 7.0 m/s. Wind classes in this range would support the newer (post-2011) and more efficient turbine models, such as the GE 1.6-100, which has a net output of 1.62 MW and a 100-m rotor diameter. Based on the average wind farm size of approximately 60 MW in the ISO-NE queue, the reference wind farm was assumed to have 37 turbines based on the GE 1.6-100.

2. Location and Site Conditions

The plant location was assumed to be in Western Maine because of the quality of the wind resources and the proximity to transmission. The characteristics of the assumed site are as follows:

- Labor cost data for Portland or Augusta, ME
- Best practice on spacing of wind turbines to minimize wake losses
- Site area of 3,840 acres based on number of turbines and spacing
- Concrete spread footing turbine foundation design
- Underground collection system
- Above ground at point of interconnection
- 115-kV interconnection with 10-mile transmission line
- Typical wind project contracting structure assumed (two main agreements for the supply and construction of the project)
- Net capacity factor based on turbine and wind class
- Wind turbine O&M service provided by turbine supplier for first five years of operation

D. SOLAR PHOTOVOLTAIC

1. Plant Configuration and Major Equipment

The plant configuration for the solar PV plant was based on the most recently developed utility-scale plants in New England, which are in the range of 2 MW to 10 MW. The representative plant was selected to have a net capacity of 6 MW, which is the largest installation that can be used to meet the Massachusetts SREC program. The larger unit sizes are more likely to be competitive entrants because of greater economies of scale. A typical solar panel for this plant size is approximately 300 W, so the required number of panels would be 20,000. The panels were assumed to be polysilicon with a fixed tilt and ground mounted since this is one of the most commonly used configurations in the industry. Polysilicon panels are usually among the most economical. Fixed tilt panels have lower up-front capital costs, but lower generating output, compared with panels mounted with single- or double-axis tracking systems.

2. Location and Site Conditions

The plant location was assumed to be in Massachusetts due to the large quantity of capacity expected to be built there during the timeframe of the auctions. The characteristics of the assumed site are as follows:

- Site area of 40 acres based on number of solar panels and spacing
- 13-kV interconnection based on recent projects in the region

- Exemption from sales tax for solar equipment purchase in Massachusetts

E. BIOMASS BOILER

1. Plant Configuration and Major Equipment

The plant configuration for the biomass plant was based on plants built in New England after 2010 and those in the ISO-NE queue, which have averaged approximately 40 MW to 50 MW. A commonly used technology has been a fluidized bed boiler. According to the National Renewable Energy Laboratory (NREL), the most likely biomass source to be available in New England is forest residues. Other features of the assumed configuration are as follows:

- Bubbling fluidized bed boiler
- 50-MW capacity
- SNCR for NO_X reduction
- Fabric filter baghouse
- Dry Sorbent Injection for HAP (HCl) reduction
- No CO catalyst
- Fuel: green chips, bark, logging residue; soft and hard woods
- Fuel handling: Shipped by truck; truck tippers; mobile yard equipment; hog/screening building; conveyors
- Fuel dryer
- Biomass storage long-term and short term
- Startup and auxiliary boiler fuel: biodiesel
- 200-foot stack
- Air cooled condenser
- No black start capability

2. Location and Site Conditions

The plant location was assumed to be in coastal Maine because, according to NREL, the state has one of the largest potential sources for forest residues in New England and because of the proximity to transmission. The characteristics of the assumed site are as follows:

- 20-acre site
- Labor cost data for Portland or Augusta, Maine
- No adjacent generating facilities, so common facilities that might otherwise be available were included in the cost estimate (e.g., switchyard, administration building, demineralized water tanks)
- 115-kV four-breaker ring bus
- Plant heat rate 13,500 But/kWh nominal
- No limit on annual operating hours per year

II. PLANT PERFORMANCE

Operating performance parameters were derived for each reference technology based on the plant configuration, location, and site conditions. The gas plant performance was estimated at Installed Capacity (ICAP) conditions of 90°F DB temperature, 72°F mean co-incident WB temperature, and 91.4% RH. A summary of plant specifications and operating performance for all technologies is presented in Table 1.

A. COMBUSTION TURBINE - PEAKER

Based on the selection of the GE LMS100 PA gas turbine in a 2 x 0 simple cycle configuration chosen, the net plant capacity of the CT plant at ICAP (90.0°F, DB) conditions is 192.3 MW, including degradation. The annual average net plant heat rate is 9,130 Btu/kWh (HHV) including degradation. The corresponding average summer (82.7°F, DB) and winter (20.7°F, DB) values are as follows:

- Summer: 200.0 MW; 9,184 Btu/kWh (HHV)
- Winter: 200.2 MW; 9,075 Btu/kWh (HHV)

B. COMBINED CYCLE GAS TURBINE

Based on the selection of the Siemens SGT6-5000F(5ee) gas turbine in a 2 x 1 combined cycle configuration, the net plant capacity of the CCGT plant at ICAP (90.0°F, DB) conditions including duct firing is 729.6 MW, including degradation. The degraded net plant capacity without duct firing is 630.8 MW. The annual average net plant heat rate is 7,138 Btu/kWh, including degradation. The corresponding average summer (82.7°F, DB) and winter (20.7°F, DB) values are as follows:

- Summer: 642.3 MW; 7,172 Btu/kWh (HHV)
- Winter: 650.1 MW; 7,104 Btu/kWh (HHV)

C. ON-SHORE WIND

The selection of a GE 1.6-100 wind turbine configured in a 37-turbine wind farm was based on the wind classes in a Western Maine location and an average wind farm size in ISO-NE queue of approximately 60 MW. The GE 1.6-100 turbine has a net output of 1.62 MW and a 100-m rotor diameter. Based upon an average wind speed of approximately 6.5 m/s and average losses of approximately 19%, this turbine model would produce an equivalent net capacity factor of approximately 35%. The average annual net generation for the wind farm would thus be approximately 184,000 MWh.

D. SOLAR PHOTOVOLTAIC

Based upon the Massachusetts site location and the selected net capacity of 6 MW, composed of 20,000 fixed-tilt, ground-mounted polysilicon solar panels of 300 W each, the expected average capacity factor is approximately 14%. The capacity factor was determined from NREL Solar Advisor Model (SAM) data for Worcester, Massachusetts. The average annual net generation for the solar plant would thus be approximately 7,400 MWh.

E. BIOMASS BOILER

Based upon the typical operating performance of other biomass facilities in the United States using fluidized bed boilers in this capacity range, the 50 MW biomass plant is estimated to have an average net plant heat rate of 13,500 Btu/kWh and an average annual capacity factor of 60%. The average annual net generation for the biomass plant would thus be approximately 262,800 MWh.

III. CAPITAL COSTS

Sargent & Lundy estimated overnight capital costs for each reference technology, expressed in 2013 $ and escalated to 2018 $. Costs are divided into major subcomponents of the engineering, procurement, and construction (EPC) costs, such as major equipment, labor, and materials, and major components of the owner's costs, such as development costs, interconnection costs, and fuel inventories. Sargent & Lundy also developed monthly construction cash flow drawdown schedules, which were used by Brattle to calculate financing costs during construction, and various cost escalation indices for the major subcomponents.

A. COMBUSTION TURBINE AND COMBINED CYCLE GAS TURBINE PLANTS

Capital investment costs for the CT and CCGT reference technologies include EPC costs, owner's costs, and financing costs during construction. The sum of the EPC and owner's costs are referred to as overnight costs:

- Costs that are typically within the scope of an EPC contract include the major equipment (gas turbines, HRSG, condenser, and steam turbine), other equipment, construction and other labor, materials, sales tax, contractor's fee, and contractor's contingency.
- Owner's costs include items not covered by the EPC scope such as development costs, oversight, legal fees, startup and testing, and training.
- Working capital and inventories refer to the initial inventories of fuel, consumables, and spare parts that are normally capitalized. It also includes working capital cash for the payment of monthly operating expenses.
- Financing fees are the cost of acquiring the debt financing including associated financial advisory and legal fees. Financing fees are part of the overnight costs. Interest costs and equity costs during construction are also part of the total capital investment cost but not part of the overnight costs.

Sargent & Lundy developed the cost estimates for the CT and CCGT reference plants from a proprietary cost estimating model in conjunction with in-house data, vendor catalogs, and publications. Overnight capital costs for the gas plants are summarized in 2013 $ in Table 2 and escalated to 2018 $ in Table 3. The monthly construction cash flow distribution is shown in Table 4.

B. ON-SHORE WIND

Sargent & Lundy estimated the capital investment costs for the on-shore wind reference plant on the basis of detailed information from a sample of nine wind projects, with rotor diameters between 82 m and 101 m, going into service between 2011 and 2013. This was supplemented by the most recent wind market report by the U. S. Department of Energy.[1] Costs within the EPC scope were broken down by the wind turbines, other equipment, construction labor, other labor, materials, EPC contractor fees, and EPC contingency. Non-EPC costs were broken down by owner's costs, electrical interconnection costs, working capital and inventories, owner's contingency, and financing fees. Costs were adjusted to be representative of a 100-m diameter rotor for consistency with the site wind speed and capacity factor assumptions previously discussed.

Overnight capital costs for the on-shore wind reference plant are summarized in 2013 $ in Table 2 and escalated to 2018 $ in Table 3. The monthly construction cash flow distribution is shown in Table 4.

C. SOLAR PHOTOVOLTAIC

Sargent & Lundy estimated the capital investment costs for the solar PV reference plant on the basis of detailed information from a sample of 12 solar PV projects, ranging in capacity from 5 MW to 20 MW, going into service between 2012 and 2015. This was supplemented by recent studies by NREL and the Lawrence Berkeley National Laboratory[2,3] and discussions with a regional solar plant developer. Costs within the EPC scope were broken down by the solar PV modules, construction labor, other labor, materials, EPC contractor fees, and EPC contingency. Non-EPC costs were broken down by owner's costs, electrical interconnection costs, working capital and inventories, owner's contingency, and financing fees.

Overnight capital costs for the solar PV reference plant are summarized in 2013 $ in Table 2 and escalated to 2018 $ in Table 3. Overnight capital costs are assumed to decline by 6%/yr in real terms between 2013 and 2018 based on historical trends and projections in the aforementioned references. The monthly construction cash flow distribution is shown in Table 4.

D. BIOMASS BOILER

Sargent & Lundy developed the cost estimate for the biomass plant from a proprietary cost estimating model in conjunction with in-house data, vendor catalogs, and publications. Costs that are typically within the scope of an

[1] *2012 Wind Technologies Market Report*, prepared by the Lawrence Berkeley National Laboratory for the U. S. Department of Energy, Wind and Water Program, May 2013.
[2] *Cost and Performance Data for Power Generation Technologies*, prepared by Black & Veatch for the National Renewable Energy Laboratory, February 2012.
[3] *Tracking the Sun VI*, Lawrence Berkeley National Laboratory, July 2013.

EPC contract include the major equipment (fluidized bed boiler, condenser, and steam turbine), other equipment, construction and other labor, materials, sales tax, contractor's fee, and contractor's contingency.

Overnight capital costs for the biomass reference plant are summarized in 2013 $ in Table 2 and escalated to 2018 $ in Table 3. The monthly construction cash flow distribution is shown in Table 4.

E. ESCALATION INDICES

Overnight capital costs for each reference technology are summarized in 2013 $ in Table 2 and escalated to 2018 $ in Table 3. The recommended cost escalation indices are available in the public domain and published on a regular basis. The gas turbines and steam turbines will be indexed to the Bureau of Labor Statistics (BLS) Producer Price Index (PPI), under the "Turbine and Turbine Generator Sets" subcategory. Wind turbines will be indexed to the Bloomberg Wind Turbine Price Index. Other equipment, materials, and interconnection costs will be indexed to various other subcategories of the PPI. Construction labor and other labor will be indexed to specific indices from the BLS Quarterly Census of Employment and Wages (QCEW). Fuel indices will be indexed to the Gross Domestic Product Deflator (GDPD). These indices, which are summarized in Table 5, will be used to escalate various subcomponents of the capital cost estimates after 2018.

IV. OPERATING COSTS

Sargent & Lundy estimated fixed and variable O&M costs for each reference technology, expressed in 2013 $ and escalated to 2018 $. Costs are broken into major subcomponents of the fixed costs, such as labor, materials, property taxes, and insurance and major components of the variable costs, such as major maintenance and consumables. Fixed and variable O&M costs for each reference technology are summarized in 2013 $ in Table 6 and escalated to 2018 $ in Table 7.

A. GAS FIRED PLANTS

1. Fixed O&M Costs

Fixed O&M costs include costs directly related to the turbine design (labor, materials, contract services for routine O&M, and administrative and general costs) and other fixed operating costs related to the location (site leasing costs, property taxes, and insurance).

2. Variable O&M Costs

a. Major Maintenance

Over the long-term operating life of a peaking facility, the largest component of variable O&M is the allowance for major maintenance expenses. Each major maintenance cycle for a combustion turbine typically includes regular combustion inspections, periodic hot gas path inspections, and one major overhaul. Since major maintenance activities and costs are spaced irregularly over the long-term, the cost in a given year represents an annual accrual for future major maintenance. For hours-based major maintenance, the average variable O&M cost ($/MWh) is equal to the total cost of parts and labor over a complete major maintenance interval divided by the factored operating hours between overhauls, divided by the unit capacity in megawatts. For starts-based major maintenance, the average variable O&M cost ($/factored start, per turbine) is equal to the total cost of parts and labor over a complete major maintenance interval divided by the factored starts between overhauls.

b. Other Variable O&M

Other variable O&M costs are directly proportional to plant generating output, such as SCR catalyst and ammonia, CO oxidation catalyst, water, and other chemicals and consumables. These items are always expressed in $/MWh, regardless of whether the maintenance component is hours-based or starts-based.

B. ON-SHORE WIND

Sargent & Lundy estimated the O&M costs for the on-shore wind reference plant on the basis of detailed information from a sample of nine wind projects, with rotor diameters between 82 m and 101 m, going into service between 2011 and 2013. This was supplemented by the most recent wind market report by the U. S. Department of Energy.[4] All O&M costs were classified as fixed, consisting of labor, materials and contract services, administrative and general, site leasing costs, property taxes, and insurance.

O&M costs for the on-shore wind reference plant are summarized in 2013 $ in Table 6 and escalated to 2018 $ in Table 7.

C. SOLAR PHOTOVOLTAIC

Sargent & Lundy estimated the O&M costs for the solar PV reference plant on the basis of detailed information from a sample of 12 solar PV projects, ranging in capacity from 5 MW to 20 MW, going into service between 2012 and 2015. This was supplemented by recent studies by NREL[5] and others. All O&M costs were classified as fixed, consisting of labor, materials, and contract services, administrative and general, site leasing costs, property taxes, and insurance.

O&M costs for the solar PV reference plant are summarized in 2013 $ in Table 6 and escalated to 2018 $ in Table 7.

D. BIOMASS BOILER

Sargent & Lundy estimated the O&M costs for the biomass reference plant on the basis of in-house data for similar biomass and fluidized bed boiler projects in this size range. O&M costs for the biomass reference plant are summarized in 2013 $ in Table 6 and escalated to 2018 $ in Table 7.

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[4] *2012 Wind Technologies Market Report*, prepared by the Lawrence Berkeley National Laboratory for the U. S. Department of Energy, Wind and Water Program, May 2013.

[5] *Cost and Performance Data for Power Generation Technologies*, prepared by Black & Veatch for the National Renewable Energy Laboratory, February 2012.

E. ESCALATION INDICES

O&M costs for each reference technology are summarized in 2013 $ in Table 6 and escalated to 2018 $ in Table 7. The recommended cost escalation indices are available in the public domain and published on a regular basis. The O&M labor and Administrative and General (A&G) costs will be indexed to the regional indices from the BLS QCEW, under the "Power Generation and Supply" subcategory. Materials and contract services will be indexed to the BLS PPI, under the "Materials and Components for Construction" subcategory. Site leasing costs will be indexed to the GDPD. These indices, which are summarized in Table 5, will be used to escalate various subcomponents of the O&M cost estimates after 2018.

Tables 1 through 7

Plant Performance and Cost Summaries

Table 1 — Plant Specifications and Performance Summary

Assumptions	Units	Combustion Turbine	Combined Cycle Gas Turbine	On-Shore Wind	Solar PV	Biomass
Plant Characteristics						
Net Plant Capacity - ICAP (with duct firing)	MW	192.3	729.6	59.9	6.0	50.0
(without duct firing)	MW	-	630.8	-	-	-
Net Plant Heat Rate - Summer/Winter Average	Btu/kWh, HHV	9,130	7,138	-	-	13,500
Equivalent Forced Outage Rate - Demand Based	EFORd	2.2%	2.0%	-	-	6.0%
Capital Costs						
EPC Contractor Fee	% of other EPC costs	10%	12%	10%	10%	6.5% **
EPC Contingency	% of other EPC costs	10%	10%	10%	10%	17.2% ***
Owner's Cost	% of EPC costs	7%	7%	7%	7%	7%
Working Capital	% of EPC costs	1%	1%	1%	1%	1%
Owner Contingency	% of other Owner's costs	8%	8%	8%	8%	8%
Financing Fees	%	4%	4%	4%	4%	4%
Electric Interconnection	$m	$4.0	$16.0	$19.0	$0.3	$14.0
Transmission Line Cost	$/mile	$4.5	$4.5	$1.7	-	$4.5
Miles	miles	0.0	0.0	10.0	-	2.0
Substation Expansion	$m	$4.0	$16.0	$2.0	-	$5.0
Gas Interconnection	$m	$3.6	$3.6	-	-	-
Pipeline Cost	$/mile	$2.5	$2.5	-	-	-
Miles	miles	0.0	0.0	-	-	-
Metering Station	$m	$3.6	$3.6	-	-	-
Sales Tax Rates	%	6.25%	6.25%	5.00%	6.25%	5.00%
State Income Tax Rates	%	8.00%	8.00%	8.93%	8.00%	8.93%
Fuel Oil Inventory Cost	$	2,529,000	7,499,000	-	-	972,000
Days of Fuel Oil Inventory	days	3	3	-	-	3
Capacity Factor for Inventory Days	%	100%	100%	-	-	100%
Fuel Oil Price	$/mmBtu	20.00	20.00	-	-	20.00
Fuel Oil Heating Value	Btu/gallon	140,000	140,000	-	-	140,000

Assumptions	Units	Combustion Turbine	Combined Cycle Gas Turbine	On-Shore Wind	Solar PV	Biomass
Fuel Oil Inventory	gallons	903,000	2,678,000	-	-	347,000
Fuel Oil Price	$/gallon	2.80	2.80	-	-	2.80
Depreciation Schedule		15yr MACRS	20yr MACRS	5yr MACRS	5yr MACRS	7yr MACRS
Tax Credits		---	---	PTC	ITC	ITC
O&M Costs						
Land	$m/yr	$0.2	$0.4	$0.8	$0.0	$0.4
Land Leasing Cost	$/acre-year	$19,000	$19,000	$200	$200	$19,000
Acreage	acre	10	20	3,840	40	20
Natural Gas Consumed During Start *	mmBtu/start, per Unit	215	1,688	-	-	540
Property Tax - Land	% of Leasing Costs	0.75%	0.75%	0.50%	0.50%	0.75%
Property Tax - Plant	% of Overnight Capital Costs	0.75%	0.75%	0.50%	0.50%	0.75%
Insurance	% of Overnight Capital Costs	0.60%	0.60%	0.30%	0.30%	0.60%

Note: All dollar numbers are in 2013$.

* May require fuel oil for biomass plant start, depending upon site infrastructure; assumes cold start for CT and warm start for CC and biomass.

** EPC contractor fee for biomass plant is based on the assumption that the boiler vendor is part of an EPC consortium and has liability only on boiler equipment.

*** Weighted average of 10% contingency on major equipment and 20% contingency on other EPC costs.

Table 2 — Capital Cost Summary – 2013 $

Units	Reference Year Overnight Costs (2013$)	Reference Year Overnight Costs (2013$)	Reference Year Overnight Costs (2013$)	Reference Year Overnight Costs (2013$)	Reference Year Overnight Costs (2013$)	
Technology	Combustion Turbine	Combined Cycle Gas Turbine	On-Shore Wind	Solar PV	Biomass	Annual Escalation Rate
Plant Capacity (MW)	192	730	60	6	50	
EPC Costs						
Equipment						
Gas Turbines	77,500,000	90,000,000	0	0	0	2.7%
Boiler / HRSG / SCR	14,000,000	43,000,000	0	0	41,193,000	2.7%
Condenser	0	26,900,000	0	0	9,000,000	2.7%
Steam Turbines	0	36,000,000	0	0	14,000,000	2.7%
Wind Turbines	0	0	77,922,000	0	0	2.7%
Solar PV Modules	0	0	0	8,100,000	0	
Other Equipment	29,013,000	50,093,000	5,994,000	0	28,726,000	2.7%
Equipment Subtotal	120,513,000	245,993,000	83,916,000	8,100,000	92,919,000	---
Construction Labor	38,612,000	154,140,000	7,193,000	2,520,000	69,082,000	3.8%
Other Labor	14,121,000	36,833,000	1,798,000	1,020,000	34,217,000	3.8%
Materials	7,007,000	33,198,000	6,593,000	2,160,000	16,638,000	2.7%
Sales Tax	7,970,000	17,449,000	4,525,000	0	5,478,000	---
EPC Contractor Fee	18,822,000	58,514,000	10,403,000	1,380,000	14,171,000	---
EPC Contingency	20,705,000	54,613,000	11,443,000	1,518,000	40,082,000	---
Total EPC Costs	227,750,000	600,740,000	125,871,000	16,698,000	272,587,000	---
Non-EPC Costs						
Owner's Costs (Services)	15,943,000	42,052,000	8,811,000	1,169,000	19,081,000	---
Electrical Interconnection	4,000,000	16,000,000	19,000,000	300,000	14,000,000	2.7%
Gas Interconnection	3,600,000	3,600,000	0	0	0	2.7%
Emission Reduction Credits	0	0	0	0	0	---
Land	0	0	0	0	0	---

Units	Reference Year Overnight Costs (2013$)	Reference Year Overnight Costs (2013$)	Reference Year Overnight Costs (2013$)	Reference Year Overnight Costs (2013$)	Reference Year Overnight Costs (2013$)	
Technology	Combustion Turbine	Combined Cycle Gas Turbine	On-Shore Wind	Solar PV	Biomass	Annual Escalation Rate
Plant Capacity (MW)	192	730	60	6	50	
Fuel Inventories	2,529,000	7,499,000	0	0	972,000	1.2%
Working Capital and Inventories	2,278,000	6,007,000	1,259,000	167,000	2,726,000	---
Owner's Contingency	2,268,000	6,013,000	2,326,000	131,000	2,942,000	---
Subtotal - Non-EPC Costs w/o Financing Fees	30,618,000	81,171,000	31,396,000	1,767,000	39,721,000	---
Financing Fees	5,167,000	13,638,000	3,145,000	369,000	6,246,000	---
Total Non-EPC Costs	35,785,000	94,809,000	34,541,000	2,136,000	45,967,000	---
Overnight Capital Costs ($)	263,535,000	695,549,000	160,412,000	18,834,000	318,554,000	-3.8%
Overnight Capital Costs ($/kW)	1,370	953	2,676	3,139	6,371	

Table 3 — Capital Cost Summary – 2018 $

Units	Reference Year Overnight Costs (2018$)	Reference Year Overnight Costs (2018$)	Reference Year Overnight Costs (2018$)	Reference Year Overnight Costs (2018$)	Reference Year Overnight Costs (2018$)	
Technology	Combustion Turbine	Combined Cycle Gas Turbine	On-Shore Wind	Solar PV	Biomass	Comments
Plant Capacity (MW)	192	730	60	6		
EPC Costs						
Equipment						
Gas Turbines	88,328,000	102,574,000	0	-	0	
Boiler / HRSG / SCR	15,956,000	49,008,000	0	-	46,948,000	
Condenser	0	30,658,000	0	-	10,257,000	
Steam Turbines	0	41,030,000	0	-	15,956,000	
Wind Turbines	0	0	88,809,000	-	0	
Solar PV Modules	0	0	0	-	0	
Other Equipment	33,066,000	57,092,000	6,831,000	-	32,739,000	
Equipment Subtotal	137,350,000	280,362,000	95,640,000	-	105,900,000	
Construction Labor	46,415,000	185,292,000	8,647,000	-	83,043,000	
Other Labor	16,975,000	44,277,000	2,161,000	-	41,132,000	Engineering, Procurement, Proj Mgt, Commissioning, etc.
Materials	7,986,000	37,836,000	7,514,000	-	18,962,000	
Sales Tax	9,084,000	19,887,000	5,158,000	-	6,243,000	
EPC Contractor Fee	21,781,000	68,118,000	11,912,000	-	16,593,000	
EPC Contingency	23,959,000	63,577,000	13,103,000	-	46,762,000	
Total EPC Costs	263,550,000	699,349,000	144,135,000	(included below)	318,635,000	

Units	Reference Year Overnight Costs (2018$)	Reference Year Overnight Costs (2018$)	Reference Year Overnight Costs (2018$)	Reference Year Overnight Costs (2018$)	Reference Year Overnight Costs (2018$)	
Technology	Combustion Turbine	Combined Cycle Gas Turbine	On-Shore Wind	Solar PV	Biomass	Comments
Plant Capacity (MW)	192	730	60	6		
Non-EPC Costs						
Owner's Costs (Services)	18,449,000	48,954,000	10,089,000		22,304,000	Permitting, Legal, Owner's Project Mgmt. & Engineering, Development Costs, & Studies.
Electrical Interconnection	4,559,000	18,235,000	21,655,000		15,956,000	
Gas Interconnection	4,103,000	4,103,000	0		0	
Emission Reduction Credits	0	0	0		0	If applicable.
Land	0	0	0		0	Included as site leasing costs in Fixed O&M.
Fuel Inventories	2,684,000	7,960,000	0		1,032,000	
Working Capital and Inventories	2,636,000	6,993,000	1,441,000		3,186,000	Includes backup fuel inventory, spare parts inventories, and other.
Owner's Contingency	2,594,000	6,900,000	2,655,000		3,398,000	
Subtotal - Non-EPC Costs w/o Financing Fees	35,025,000	93,145,000	35,840,000		45,876,000	
Financing Fees	5,972,000	15,850,000	3,600,000		7,290,000	
Total Non-EPC Costs	40,997,000	108,995,000	39,440,000	(included below)	53,166,000	
Overnight Capital Costs ($)	304,547,000	808,344,000	183,575,000	15,558,000	371,801,000	
Overnight Capital Costs ($/kW)	1,583	1,108	3,063	2,593	7,436	

Table 4 — Construction Cash Flow Distributions

Technology	Months Until Completion	Construction Month 1	2	3	4	5	6	7	8	9	10
Combustion Turbine	20	0.36%	0.43%	2.61%	0.80%	1.75%	1.11%	2.18%	2.89%	4.03%	6.70%
Combined Cycle Gas Turbine	36	0.01%	0.04%	0.04%	1.42%	1.39%	0.20%	0.31%	1.22%	1.29%	1.08%
On-Shore Wind	32	0.10%	0.20%	0.20%	0.40%	0.40%	0.40%	0.40%	0.40%	0.40%	3.70%
Solar PV	24	0.12%	0.15%	0.48%	0.53%	0.34%	0.50%	0.64%	1.64%	1.78%	1.53%
Biomass	31	3.31%	2.77%	2.44%	3.31%	4.35%	4.70%	5.11%	5.95%	5.60%	5.38%

Technology	Months Until Completion	11	12	13	14	15	16	17	18	19	20
Combustion Turbine	20	8.14%	10.41%	11.57%	12.27%	11.49%	10.16%	7.71%	4.28%	0.91%	0.20%
Combined Cycle Gas Turbine	36	1.14%	1.21%	2.11%	2.31%	3.27%	3.57%	4.07%	4.48%	5.24%	5.34%
On-Shore Wind	32	3.70%	3.70%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
Solar PV	24	1.78%	2.23%	5.06%	5.81%	6.29%	8.07%	15.45%	15.13%	9.13%	8.13%
Biomass	31	5.13%	5.14%	6.81%	6.15%	4.83%	4.21%	3.99%	3.74%	3.75%	3.38%

Technology	Months Until Completion	21	22	23	24	25	26	27	28	29	30
Combustion Turbine	20	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Combined Cycle Gas Turbine	36	5.22%	5.38%	5.11%	5.06%	5.23%	5.22%	5.26%	4.94%	4.86%	4.15%
On-Shore Wind	32	2.50%	11.30%	11.30%	11.30%	4.80%	4.80%	4.80%	4.80%	4.80%	4.80%
Solar PV	24	6.82%	5.43%	2.60%	0.35%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Biomass	31	2.59%	2.06%	1.49%	1.06%	0.89%	0.64%	0.39%	0.29%	0.21%	0.15%

Technology	Months Until Completion	31	32	33	34	35	36	37	38	39	40	Total
Combustion Turbine	20	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%
Combined Cycle Gas Turbine	36	3.77%	3.01%	2.18%	0.60%	0.14%	0.10%	0.00%	0.00%	0.00%	0.00%	100.00%
On-Shore Wind	32	0.60%	0.20%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%
Solar PV	24	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%
Biomass	31	0.15%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%

Table 5 — Escalation Indices

	Combustion Turbine	Combined Cycle Gas Turbine	On-Shore Wind	Solar PV	Biomass
EPC Costs					
Equipment					
Gas Turbines	PPI Turbines	PPI Turbines	-	-	-
Boiler / Heat Recovery Steam Generator	PPI Equipment	PPI Equipment	-	-	PPI Equipment
Condenser	-	PPI Equipment	-	-	PPI Equipment
Steam Turbines	-	PPI Turbines	-	-	PPI Turbines
Wind Turbines	-	-	Bloomberg Wind	-	-
Solar Panels	-	-	-	-	-
Other Equipment	PPI Equipment	PPI Equipment	PPI Equipment	-	PPI Equipment
Equipment Subtotal	-	-	-	-	-
Construction Labor	Utility Const Wage_MA	Utility Const Wage_MA	Utility Const Wage_ME	-	Utility Const Wage_ME
Other Labor (Eng, Procurement, Proj Mgt, Commissioning, etc.)	Power Gen Wage_MA	Power Gen Wage_MA	Power Gen Wage_ME	-	Power Gen Wage_ME
Materials	PPI Materials	PPI Materials	PPI Materials	-	PPI Materials
Sales Tax	-	-	-	-	-
EPC Contractor Fee	-	-	-	-	-
EPC Contingency	-	-	-	-	-
Subtotal - EPC Costs	-	-	-	(included below)	-
Non-EPC Costs					
Owner's Costs (Services)	-	-	-	-	-
Electrical Interconnection	PPI - Elect. Dist.	PPI - Elect. Dist.	PPI - Elect. Dist.	-	PPI - Elect. Dist.
Gas Interconnection	PPI - Gas Dist.	PPI - Gas Dist.	PPI - Gas Dist.	-	PPI - Gas Dist.
Emission Reduction Credits	-	-	-	-	-
Land	-	-	-	-	-
Fuel Inventories	GDPD	GDPD	GDPD	-	GDPD
Working Capital	-	-	-	-	-
Owner's Contingency	-	-	-	-	-
Subtotal - Non-EPC Costs w/o Financing Fees	-	-	-	-	-

	Combustion Turbine	Combined Cycle Gas Turbine	On-Shore Wind	Solar PV	Biomass
Financing Fees	-	-	-	-	-
Subtotal - Non-EPC Costs	-	-	-	(included below)	-
Overnight Capital Costs ($)	-	-	-	LBNL	-
Overnight Capital Costs ($/kW)	-	-	-	LBNL	-
Fixed O&M Costs					
Labor	Power Gen Wage_MA	Power Gen Wage_MA	Power Gen Wage_ME	Power Gen Wage_MA	Power Gen Wage_ME
Materials and Contract Services	PPI Materials	PPI Materials	PPI Materials	PPI Materials	PPI Materials
Administrative and General	Power Gen Wage_MA	Power Gen Wage_MA	Power Gen Wage_ME	Power Gen Wage_MA	Power Gen Wage_ME
Site Leasing Costs	GDPD	GDPD	GDPD	GDPD	GDPD
Property Taxes	-	-	-	-	-
Insurance	-	-	-	-	-
Total Fixed O&M ($)	-	-	-	-	-
Total Fixed O&M ($/kW-year)	-	-	-	-	-

Notes:

1) PPI Turbines = BLS - PPI "Turbines and Turbine Generator Sets"
2) Bloomberg Wind = "Wind Turbine Price Index"
3) PPI Equipment = BLS - PPI "General Purpose Machinery and Equipment"
4) Utility Const Wage = "BLS - QCEW Utility System Construction"
5) Power Gen Wage = "BLS - QCEW Power Generation and Supply"
6) PPI Materials = BLS - PPI "Materials and Components for Construction"
7) PPI - Elect. Dist. = BLS-PPI ‘Electric Power Transmission, Control and Distribution’
8) PPI - Gas Equip. = BLS-PPI ‘Natural Gas Distribution’
9) GDPD = Gross Domestic Product Deflator
10) LBNL = Lawrence Berkeley National Laboratory, *Tracking the Sun* reports.

Table 6 — O&M Cost Summary – 2013 $

O&M Costs (2013 $)	Combustion Turbine	Combined Cycle Gas Turbine	On-Shore Wind	Solar PV	Biomass	Annual Escalation Rate
Fixed O&M						
Labor	882,000	2,938,000	599,000	54,000	2,480,000	3.8%
Materials and Contract Services	308,000	4,018,000	599,000	72,000	2,310,000	2.7%
Administrative and General	335,000	793,000	899,000	36,000	1,440,000	2.7%
Site Leasing Costs	190,000	380,000	768,000	8,000	380,000	2.3%
Property Taxes	1,978,000	5,219,000	806,000	94,000	2,392,000	
Insurance	1,581,000	4,173,000	481,000	57,000	1,911,000	
Total Fixed O&M ($)	5,274,000	17,521,000	4,152,000	321,000	10,913,000	
Total Fixed O&M ($/kW-year)	27.42	24.01	69.27	53.50	218.26	
Variable O&M						
Major Maintenance - Hours Based	2.86	1.31	-	-	-	2.7%
Consumables, Waste Disposal, and Other VOM	2.52	1.03	-	-	3.20	2.7%
Variable O&M - Hours Based ($/MWh)	5.38	2.34	0.00	0.00	3.20	
Variable O&M - Starts Based ($/factored start, per turbine)	-	9,164	-	-	-	2.7%

Table 7 — O&M Cost Summary – 2018 $

O&M Costs (2018 $)	Combustion Turbine	Combined Cycle Gas Turbine	On-Shore Wind	Solar PV	Biomass	Comments
Fixed O&M						
Labor	1,060,000	3,532,000	720,000	65,000	2,981,000	
Materials and Contract Services	351,000	4,579,000	683,000	82,000	2,632,000	
Administrative and General	382,000	904,000	1,025,000	41,000	1,641,000	
Site Leasing Costs	212,000	425,000	858,000	9,000	425,000	
Property Taxes	2,286,000	6,066,000	922,000	78,000	2,792,000	
Insurance	1,827,000	4,850,000	551,000	47,000	2,231,000	
Total Fixed O&M ($)	6,118,000	20,356,000	4,759,000	322,000	12,702,000	
Total Fixed O&M ($/kW-year)	31.81	27.90	79.40	53.67	254.04	
Variable O&M						
Major Maintenance - Hours Based	3.26	1.49	-	-	-	CT and CC value is zero if starts-based major maintenance.
Consumables, Waste Disposal, and Other VOM	2.87	1.17	-	-	3.65	
Variable O&M - Hours Based ($/MWh)	6.13	2.67	0.00	0.00	3.65	
Variable O&M - Starts Based ($/factored start, per turbine)	-	10,444	-	-	-	CT and CC value is zero if hours-based major maintenance.

Last page of technical appendix.

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