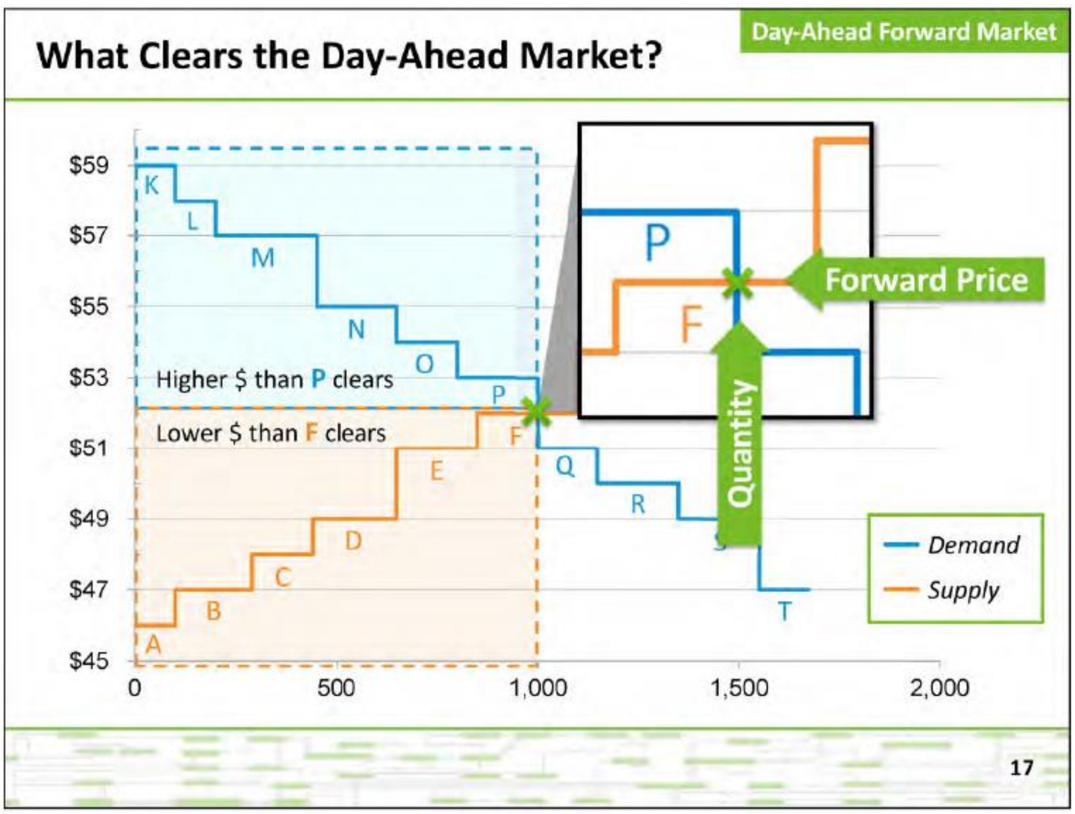
Appendix B - Key Variables

As referenced in Chapter 7, Decision Tree analysis, BED staff developed, in coordination with the IRP Committee, projections of several key input variables that were integral to modeling BED's NPV cost of service. The key variables analyzed were wholesale energy prices, wholesale capacity prices, transmission prices, and renewable energy credit (REC) prices. It is important to note, that general economic inflation and wood price inflation are also important key input variables to the cost of service models. Indeed, higher than expected inflationary pressures would almost certainly increase the overall cost to provide service to the City. However, because inflation affects all of the plausible decision pathways in the same way, BED staff and the IRP committee members did not further evaluate its potential impact.

To evaluate the viability of several potential future decision pathways, as well as the range of risks that the above noted key input variables could impose upon BED's customers, three case scenarios were constructed - base, low, and high cases. Base cases represented a continuation of current trends, unless specific future changes were known and expected. Low case scenarios were designed to reflect circumstances in which values would fall below current and historical trends. High case scenarios represented circumstances in which values were forecasted to exceed current and historical trends. Within these three case scenarios, BED staff and the IRP Committee members individually assigned probabilities to each of the key input variables based on the best available information. The individual probability assignments were then aggregated to create a single group average (or weighted value) for each variable input. The group averages were then used to inform an additional scenario – a "consensus" scenario – that was used to calculate additional estimates of BED's NPV cost of service for each plausible decision pathway option. These estimates are depicted as the red dots on the scatter plot included in Chapter 7. Thus, 11 values were studied for each variable; low, base, high, weighted value, and seven individual scores (three staff and four IRP Committee members). The high, base, and low case values, as well as the group averages for each variable are discussed in greater detail, below.

Two key variables, energy prices and capacity prices, are significantly influenced by the wholesale markets administered by ISO-New England (ISO-NE). In the energy market, wholesale energy is bought and sold in the Day Ahead (DA) or the Real Time (RT) energy markets. The DA market is a financial forward market that allows market participants (buyers and sellers) to secure prices for electric energy the day before the operating day and hedge against price fluctuations that can occur in real time during the operating day should electric energy supply or demand deviate from expectations.[1] In the DA market, load serving entities submit demand bids into ISO – NE for electric energy they anticipate needing the next day. Their bid indicates the maximum price they would be willing to pay as well as the total MWhs they expect to need in each hour of the operating day. Similarly, generators submit supply offers into the DA market for the energy they anticipate being able to provide the next day. Their supply bids reflect the minimum price per MWh that they are willing to accept. On a daily basis, ISO-NE compares the demand bids and supply offers and clears the DA market at the price where the supply and demand curves intersect. Cleared bids establish the price for electricity to be delivered and bought during the next day, as well as the total quantity of MWhs.

Figure 1: ISO Market Clearing process[2]



The RT market is a physical delivery market and is sometimes referred to as a deviation market. Financially, the real-time energy market settles the differences between the day-ahead

[1] ISO-New England (2015). *Introduction to ISO-New England,* p111-112 http://www.iso-ne.com/static-assets/documents/2014/08/ISO101-handbook-complete.pdf

[2] Source: ISO New-England (2015) *Introduction to ISO-New England,* p135.

scheduled amounts of load and generation and the actual real-time load and generation. Participants either pay or are paid the real-time price for the amount of load or generation in megawatt-hours (MWh) that deviates from their day-ahead schedule, whether they are a load serving entity or a generator. [3]

Compared to the energy markets, the Forward Capacity Market (FCM) is a longer-term wholesale market. This market is designed to bolster consumer confidence in the system's ability to provide for sufficient amounts of resources where they are needed the most. To accomplish this objective, ISO – NE conducts Forward Capacity Auctions (FCAs) each year as a means to attract capacity resources (supply, energy efficiency and demand responses) to serve loads throughout the region. Market actors (i.e. generators or energy service companies) compete on price to win commitments to supply capacity resource(s) in exchange for a market-priced capacity payment. Load serving entities are charged on a per MW of load basis using the prices that are set in the FCAs.[4]

BED's position as a generator and load serving entity adds a layer of complexity to understanding how wholesale energy and capacity prices impact BEDs cost of service. For BED, day – ahead (and real – time) energy settlements and FCM payments represent both revenues and costs. BED's generators earn revenues when its energy and capacity bids are cleared by ISO – NE. But energy and capacity also represent costs as a load serving entity. All things being equal, higher energy or capacity prices typically result in additional revenues for BED as a generator. However, higher prices also increase the cost to serve BED's load. If BED has excess energy (i.e. long energy), increased load cost can be offset by increases in revenues earned from generation. But, in situations where BED is short on either energy or capacity and must purchase additional supply at higher prices to serve its load, the revenue from generation are largely offset by the higher cost to serve load. So long as BED is able to maintain a balance, in most hours, between generation bids and load commitments, BED's costs to serve load should not be materially affected by ISO – NE's wholesale energy market rules. However, if energy and capacity prices continually increase overtime so does the cost to serve load (and vice versa). Table 1, below, provides a summary of the potential impacts of wholesale prices on BED from the perspective of both a generator and load serving entity.

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[3] ISO-New England (2015). *Introduction to ISO-New England,* pg. http://www.iso-ne.com/static-assets/documents/2014/08/ISO101-handbook-complete.pdf

[4] ISO-New England (2015). *Introduction to ISO-New England,* p150. http://www.iso-ne.com/static-assets/documents/2014/08/ISO101-handbook-complete.pdf

Table 1: Wholesale energy & capacity prices

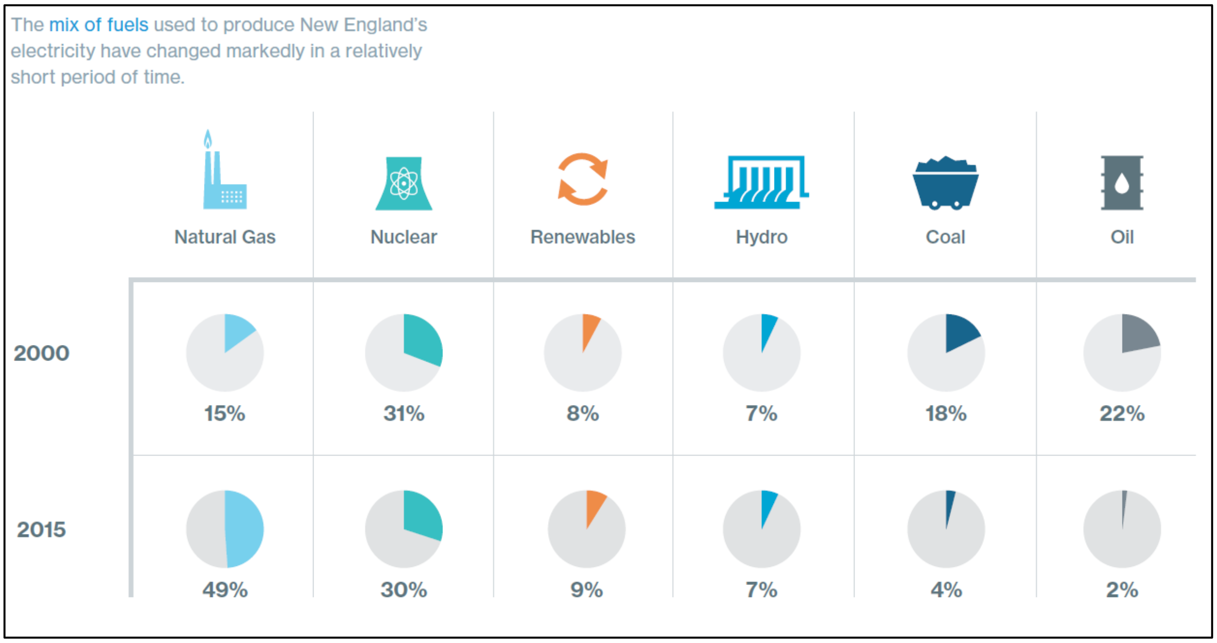
ISO NE Wholesale Prices BED dual perspectives -			
		Hi prices	Low prices
Long Energy & Capacity		Benefit, higher revenues	Cost (lost revenue)
Short Energy & Capacity		Cost (lost revenue)	Benefit(lower rates)

Wholesale Energy Prices

Wholesale energy is both a significant cost to BED and revenue source. Thus, forecasts of wholesale energy prices materially influence the attractiveness, feasibility and estimated cost-effectiveness of various resource options. Due to its significance, wholesale energy prices represent a major risk factor to BED that needs to closely monitored and managed, especially since wholesale prices greatly influence the retail rates paid by customers. However, whether rates rise or fall overtime depends in large part on whether BED is long or short in terms of energy supply, as noted above.

Forecasting wholesale energy prices is challenging. Future prices are influenced by myriad factors, including but not limited to New England's reliance on natural gas, generator fuel costs, fuel availability and delivery options, supply changes (such as generator availability, retirements, or construction of new units), transmission constraints, and changes in energy demand. In New England, wholesale electric energy prices are highly correlated with natural gas prices as natural gas fired generators produce approximately 50% of the energy supply. As dominate players in the region, these generators typically set wholesale electric prices in the DA markets. BED expects that natural gas generation will continue to be a dominate supply resource in New England and that wholesale electric energy prices will continue to closely track natural gas prices. Accordingly, estimates of future wholesale electric prices for this IRP began with developing a base case scenario of natural gas forward prices based on published price forecasts.

Figure 2: Fuel Mix in New England



Source: ISO New-England (2016) *2016 Regional Electricity Outlook*, p8.

Base Case

For the energy price base case scenario, BED first estimated natural gas prices into the future and then assumed an average heat rate for all combined cycle generation to develop a MWh price trajectory. Such prices were estimated for on-peak hours, off-peak peak, and 8760 energy price forecasts. The natural gas price forecast consists of an undelivered natural gas price forecast, a natural gas price growth rate, and basis differential.

- Natural Gas Price Forecast:
    - Undelivered Natural Gas Price - BED began with actual 2016-2020 forward prices for natural gas at Henry Hub.
    - Natural Gas Price Growth Rate – BED applied the Energy Information Agency's April 2015 Annual Energy Outlook growth rate for the 2021-2037 period to the 2020 Henry Hub forward price to complete the Undelivered Natural Gas Price Forecast for 2016-2037.
    - Delivery Basis Differential – BED used the actual basis differential between Henry Hub and Algonquin City Gate forward prices for the 2016-2020 period and then held the basis differential constant at the 2020 level for the 2021-2037 period. The Undelivered Natural Gas Price Forecast and the Delivery Basis Differential were added together to arrive at the Natural Gas Price Forecast for 2016-2037.

- Heat Rate – BED applied the average of the 2013-2015 period's actual peak, off-peak, and all hours heat rates for the MA Hub to the 2016-2037 Natural Gas Price Forecast values to arrive at the 2016-2037 Energy Price Forecast Base Case.

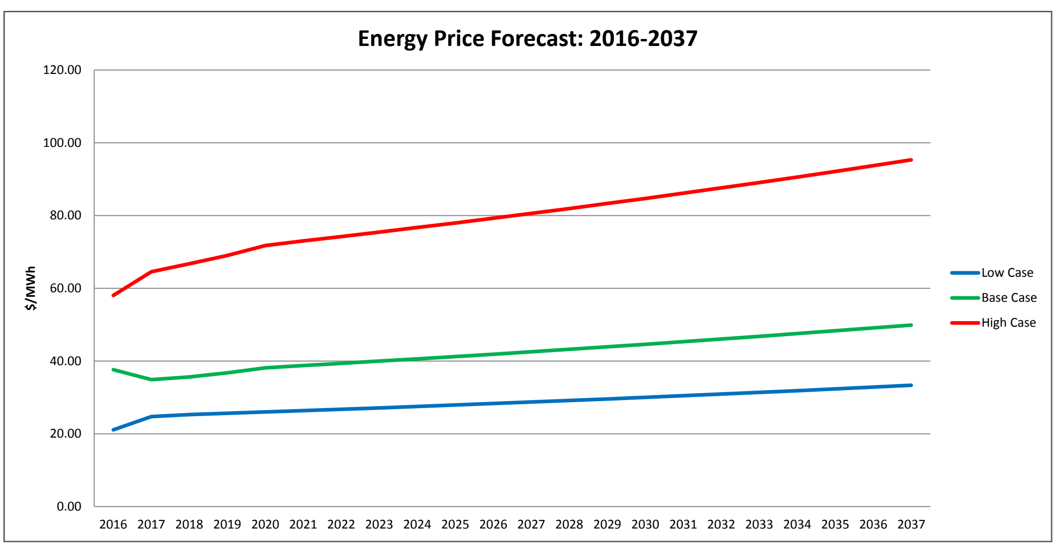
Low Case

The Henry Hub natural gas distribution point in Louisiana has historically been used as a benchmark source for undelivered natural gas prices. However, the availability of significant natural gas resources from the Marcellus Shale in Pennsylvania made possible by advances in hydraulic fracturing suggests using prices from the Dominion South distribution point could provide a more accurate natural gas pricing in the northeast US. Given that the Dominion South prices have been significantly lower than the Henry Hub prices, those prices were used in the development of the energy price low case. Specifically, the low case natural gas price is comprised of Dominion South undelivered natural gas prices plus a small delivery basis charge representing unconstrained delivery to New England. The same heat rate used in the base case was applied to the natural gas price to arrive at the peak, off-peak, and all hours energy prices.

High Case

In the high case, the Henry Hub undelivered natural gas base case prices were increased by 200% and a higher delivery differential based on the 2009-2013 average Algonquin delivery differential was added for the full 2016-2037 period.

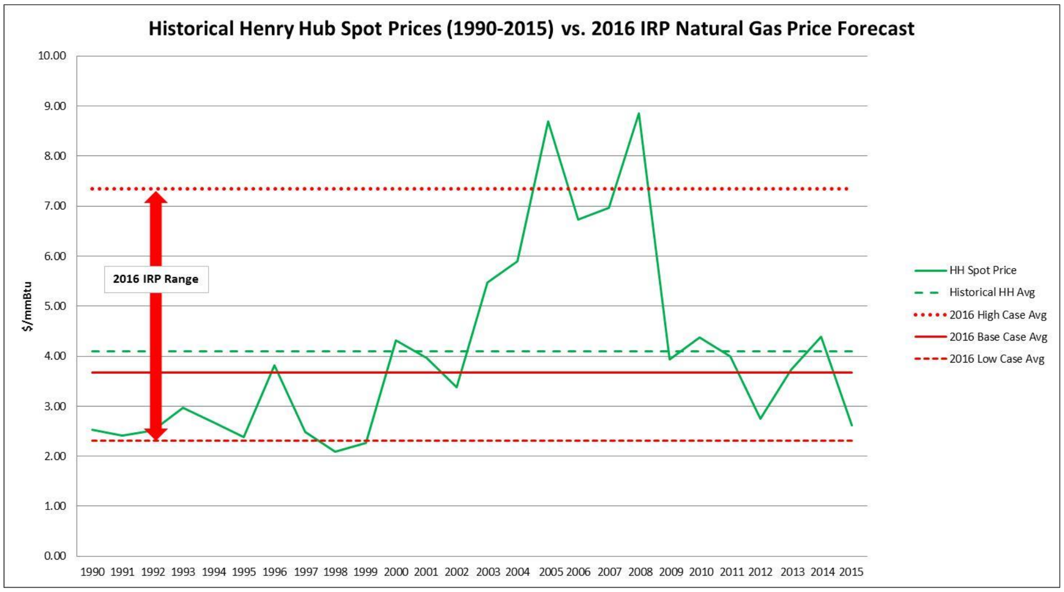
Figure 3: Energy Price forecast



Error! Reference source not found.4 illustrates how forecasts for energy prices under the high and low case scenarios compare to historical natural gas prices. The green dashed line reflects historical Henry Hub average price and is slightly higher than the base case natural gas price.

The red lines represent the average values over the IRP time horizon for the high, base, and low cases. The "2016 Low Case Avg" represented by the red dashed line is based on the Dominion South natural gas price forecast and clearly represents a lower natural gas price than the historical Henry Hub experience.

Figure 4: Natural Gas spot prices



Wholesale Energy Price Probabilities & Weighted Values

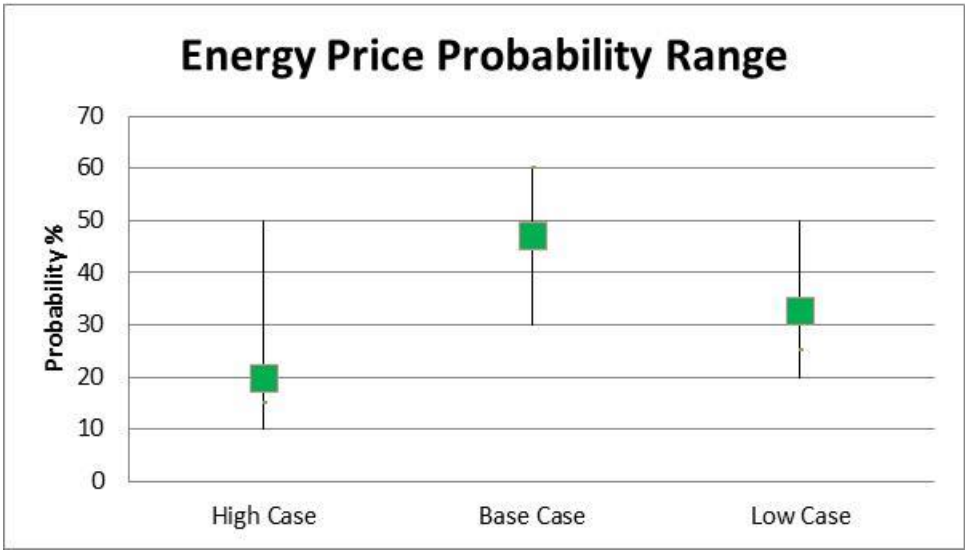
Error! Reference source not found. , below, provides the individual energy price probability assignments made by staff and the IRP Committee members, as well as the group average. **Error! Reference source not found.**5 provides a visual representation of the range of probability values associated with each energy price case.

Table 2 Energy Price Probability Assignments

	Energy Price Probability Assignments		
	High Case	Base Case	Low Case
Staff 1	15%	60%	25%
Staff 2	10%	60%	30%
Staff 3	20%	40%	40%
Committee Member 1	50%	30%	20%
Committee Member 2	15%	50%	35%
Committee Member 3	20%	50%	30%
Committee Member 4	10%	40%	50%
Group Average	**20%**	**47%**	**33%**

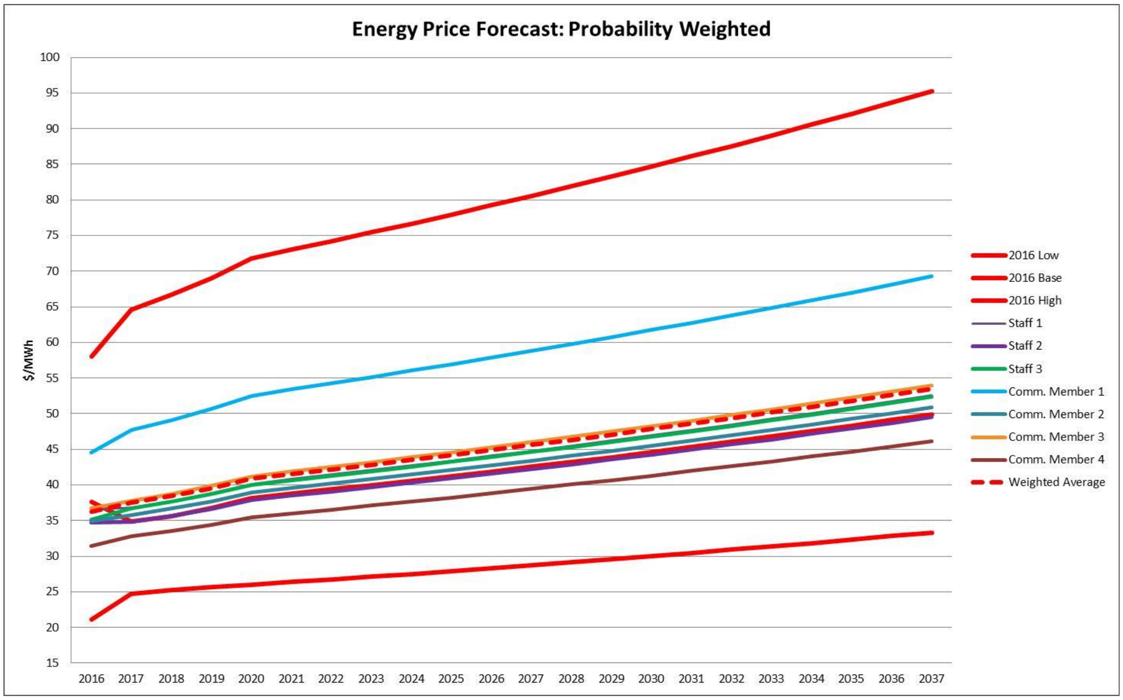
Appendix B - 8

Figure 5: Energy Price probability range



The energy price probability assignments primarily clustered around the base case with one projection significantly higher than the others due to assigning a 50% probability to the high case. The combined committee and staff ratings resulted in the following aggregate probability assignments: High Case, 20%; Base Case, 47%; Low Case, 33%. Figure 6 represents the application of the individual energy price probability assignments as well as the group average to the high, base, and low cases. The single weighted average energy price forecast resulting from the group average probability assignment is represented by the dashed red line, which is slightly above the base case levels.

Figure 6: Energy prices



Using shale gas pricing (Dominion South) to develop the low case values recognizes the current robust state of natural gas production in the Northeast. However, discussions amongst staff and IRP Committee members suggested some concern about future upward pressure on natural gas prices due to either pipeline constraints or limits on natural gas drilling techniques, as indicated by the majority of individual weighting results above the base case.

Capacity Price Forecast

Distribution utilities like BED are required by ISO-NE to ensure the availability of sufficient energy-producing resources to meet the BED system peak load, measured annually, plus a reserve margin that accounts for potential generator or transmission outages. BED's capacity requirement is known as its Capacity Load Obligation (CLO). For every kW of CLO, BED must pay the applicable capacity price for the current time period, measured in $/kW-month. BED's owned generating resources and certain contracted resources are able to supply capacity, either as an offset to BED's CLO or as a capacity resource available to meet other capacity demands in the ISO-New England region. Therefore, capacity prices influence BED's expenses as well as potential revenues. The price of capacity BED must pay to cover its CLO as well as the prices it receives for capacity supply resources are set by the ISO-NE Forward Capacity Market (FCM). Similar to energy prices, as both an owner of capacity-producing resources and as a load serving entity, changes in capacity prices can have varying effects on BED's bottom line. Also, lower capacity prices do not always result in positive net benefits to BED customers. If BED has excess capacity to sell, lower prices would increase net costs to customers. On the other hand, if BED is short on capacity and needed to purchase additional capacity through the wholesale market, lower capacity prices would reduce BED's net cost to serve load.

The FCM is the mechanism by which the total capacity needs of the New England region, known as the Installed Capacity Requirement (ICR), are met with capacity supply. Introducing new capacity to the New England region in most circumstances requires a significant capital investment, either through the construction of a new generating resource or significant upgrades to existing generating resources. For that reason, BED's capacity price forecast includes the consideration of construction cost trends.

Base Case

The capacity price base case was developed by applying a Construction Cost Index (CCI) growth rate to the most recent FCM auction price. The most recent FCM auction was Forward Capacity Auction (FCA) 10, which concluded on February 8, 2016 with a clearing price of $7.03/kW-month for the June 2019-May 2020 period. The CCI is prepared by Engineering News Review and made available to the United States Department of Agriculture. The CCI includes data from 1908 to the present. For purposes of this analysis, BED calculated the average CCI growth rate for the six year period ending in 2015 and applied it to the calendar year equivalent of actual FCA clearing prices to develop base case projections of capacity values for 2020-2037.

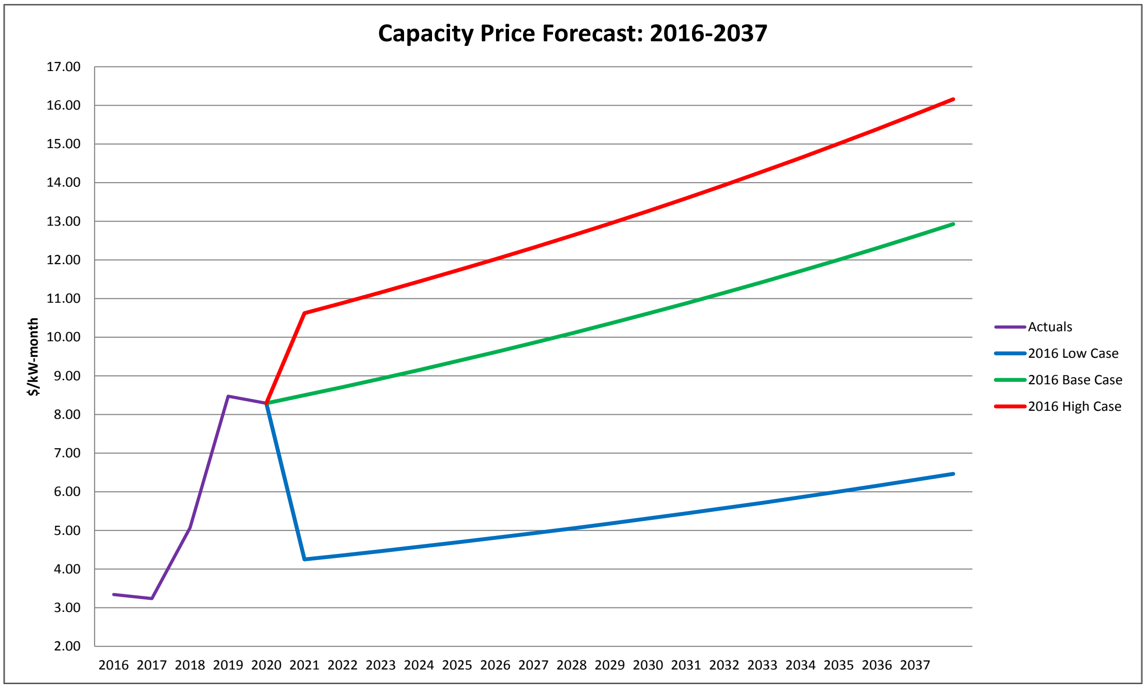
Low Case

The low case set the capacity prices at 50% of the base case values. Circumstances that could push FCM capacity prices lower include, but are not limited to, reduced or flattened peak demand (either through efficiency or distributed generation) that lowers the region's ICR, improved transmission that increases the potential for capacity imports into the region, or the development of capacity-producing resources that are less expensive than traditional fossil-fuel fired peaking units.

High Case

The high case set the capacity prices at 125% of the base case values. Circumstances that could push FCM capacity prices higher include, but are not limited to, peak load growth due to increased electrification (such as electric vehicles or heat pumps), generator retirements that require the construction of new capacity-producing resources, or increased FCM auction offer prices due to new "pay for performance" guidelines that will increase the risk for capacity-supplying resources.

Figure 7: Capacity Prices



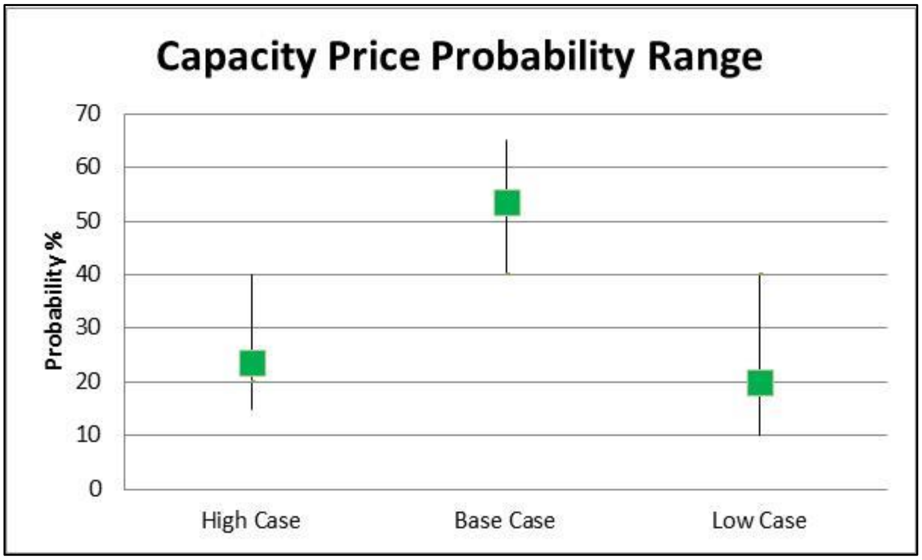
Capacity Price Probabilities & Weighted Values

Table 3 provides the individual capacity price probability assignments made by staff and the IRP Committee members, as well as the group average. **Error! Reference source not found.**7 and 8 provide a visual representation of the range of probability values associated with each capacity price case.

Table 3

	Capacity Price Probability Assignments		
	High Case	Base Case	Low Case
Staff 1	15%	60%	25%
Staff 2	15%	60%	25%
Staff 3	20%	40%	40%
Committee Member 1	40%	50%	10%
Committee Member 2	20%	60%	20%
Committee Member 3	40%	50%	10%
Committee Member 4	25%	65%	10%
Group Average	**25%**	**55%**	**20%**

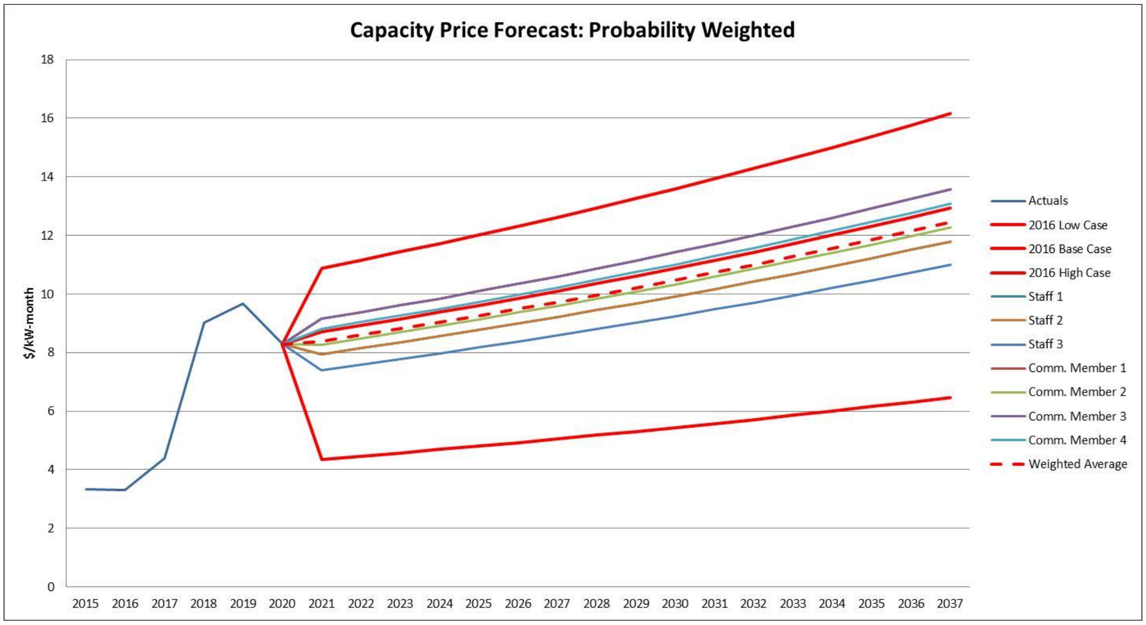
Figure 8:



The probability ranges indicate relatively strong concurrence, with weighted capacity values relatively tightly clustered around the base case. The combined committee and staff probability ratings resulted in the following aggregate probability assignment: High Case, 25%; Base Case, 55%; Low Case, 20%.

Figure 9: Capacity Price forecast, below, represents the application of the individual capacity price probability assignments as well as the group average to the high, base, and low cases. The single weighted average capacity price forecast resulting from the group average probability assignment is represented by the dashed red line, which is slightly below the base case levels.

Figure 9: Capacity Price forecast

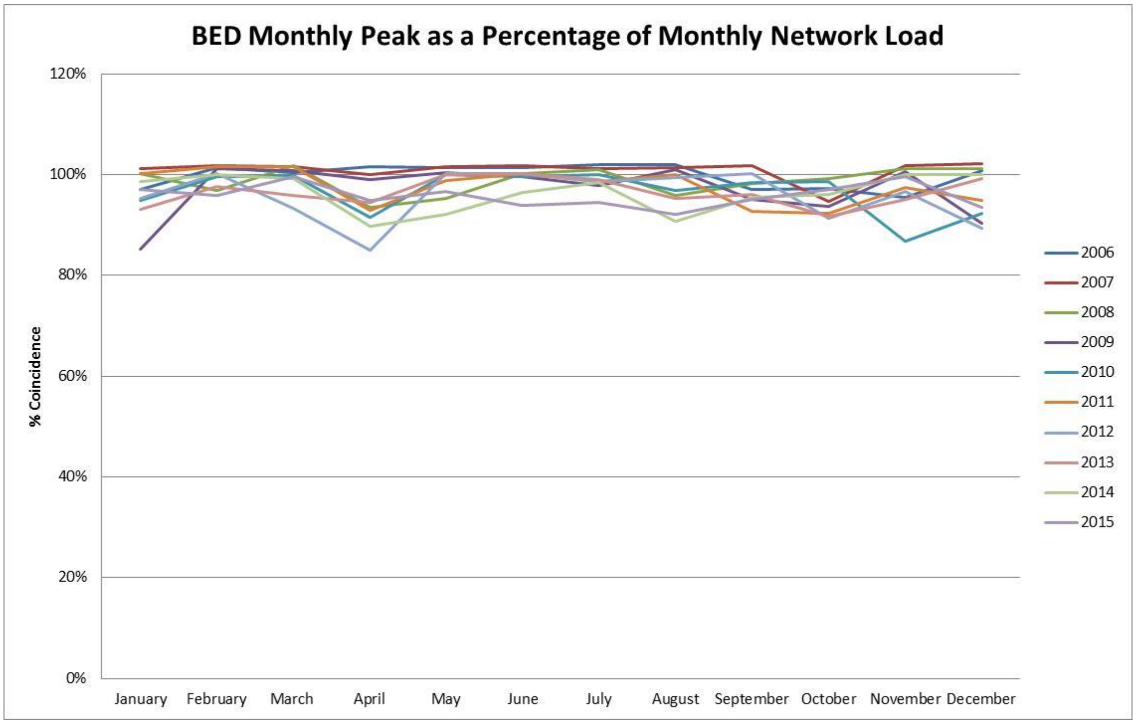


The strong concurrence of the weighted values around the base case, with values ranging from \$8.29 to \$12.93 during the IRP time horizon, seems consistent with the current FCM mechanics. The most recent cost of new entry (NET CONE) was set at \$10.81, which represents the cost to construct a new peaking unit on a kW-month basis. If, in any given year, there is insufficient capacity and the FCA clearing price exceeds NET CONE, the expectation is that a new capacity producing unit would be constructed, which would then push prices toward NET CONE. Additionally, the existence of an FCA ceiling price, most recently set at \$17.30, places an upper limit on prices in the case of an extreme shortage event.

Transmission Price Forecast

The bulk of the transmission charges BED incurs are related to the Regional Network Service (RNS) fee, which is assessed per KW based on BED's contribution to Vermont's peak monthly load. Transmissions costs are therefore closely tied to the magnitude of BED's system load compared to Vermont's load. If BED's load increases or decreases at a different rate than Vermont's total load, or shifts to a different time, BED will have to cover an increasing or decreasing share of the RNS charges. Figure 10 illustrates the current coincidence between BED's monthly peak load and its share of the monthly Vermont peak (Network Load). For the purposes of this variable analysis, it was assumed that BED's load remains constant and the only dynamic component is the actual charge per KW. The price per KW is influenced by the cost to maintain the existing regional transmission infrastructure as well as the cost to construct new transmission infrastructure, including replacement and expansion.

Figure 10



Base Case

The transmission price base case was developed by applying a Construction Cost Index (CCI) to the most recent Regional Network Service (RNS) price forecast, which was made available by NEPOOL in August 2015 and provided price estimates for the 2016-2019 period. The CCI prepared by Engineering News Review is made available by the United States Department of Agriculture for 1908-present. BED used the average CCI growth rate for the 2010-2015 period and applied it to the 2019 RNS forecast price to arrive at the 2016-2037 Transmission Price Forecast Base Case.

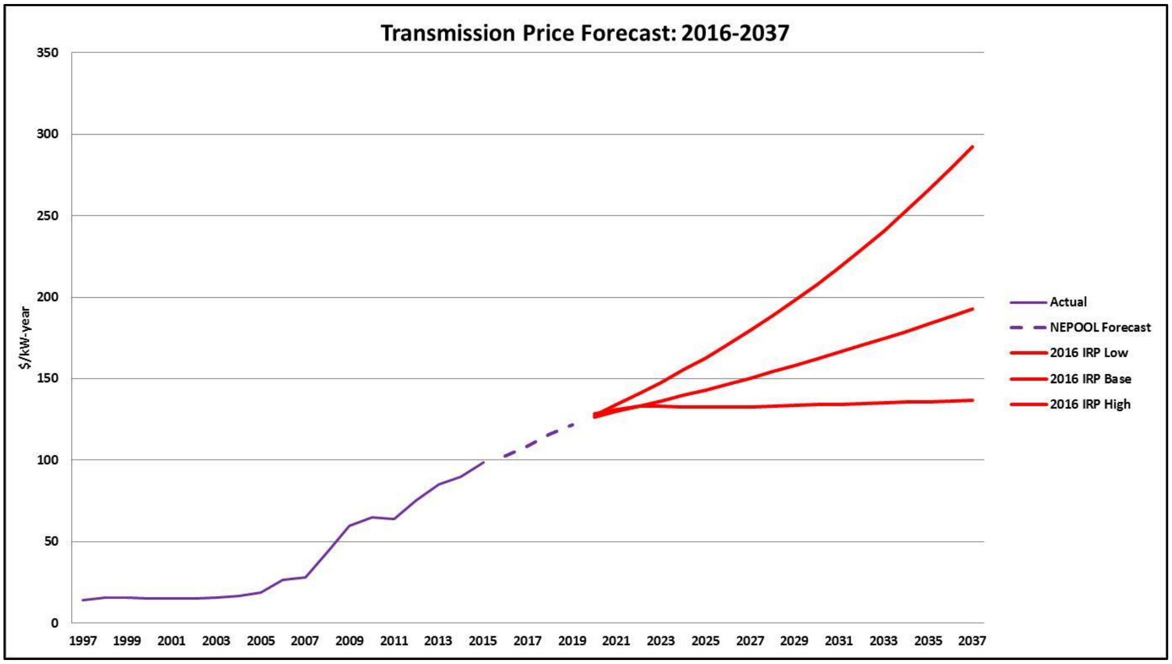
Low Case

Like the base case, the low case began with the 2019 NEPOOL RNS forecast. Rather than applying the CCI growth rate to the 2019 forecast, a lower growth rate projected by VELCO was used. The growth rate reflects VELCO's expected increases to its share of the RNS costs for the 2020-2031 period. The low case forecast carried the 2031 growth rate value forward through to 2037.

High Case

As with the base and low cases, the high case began with the 2019 NEPOOL RNS forecast. A 5% annual growth rate was then applied to the NEPOOL forecast.

Figure 11: Transmission prices



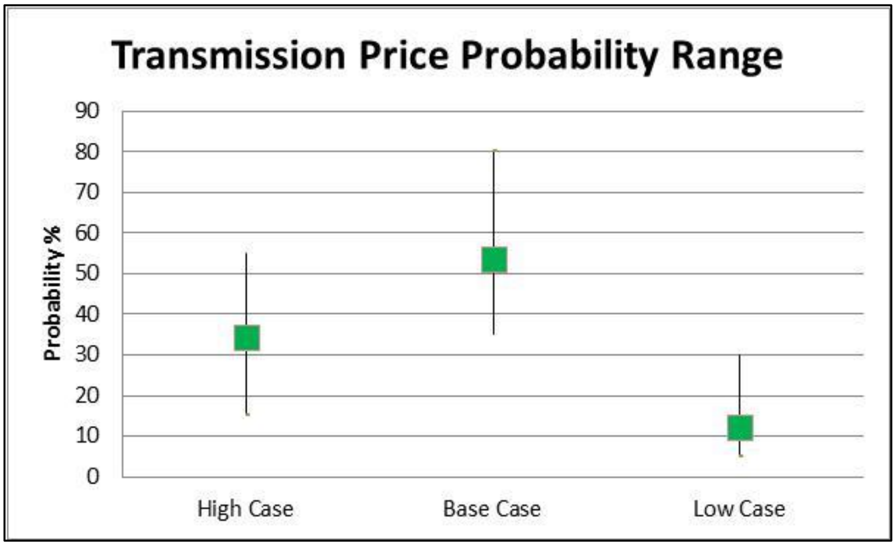
Transmission Price Probabilities & Weighted Values

Table 4 provides the individual transmission price probability assignments made by staff and the IRP Committee members, as well as the group average. Figure 1211 and 12 are a visual representation of the range of probability values associated with each transmission price case.

Table 4

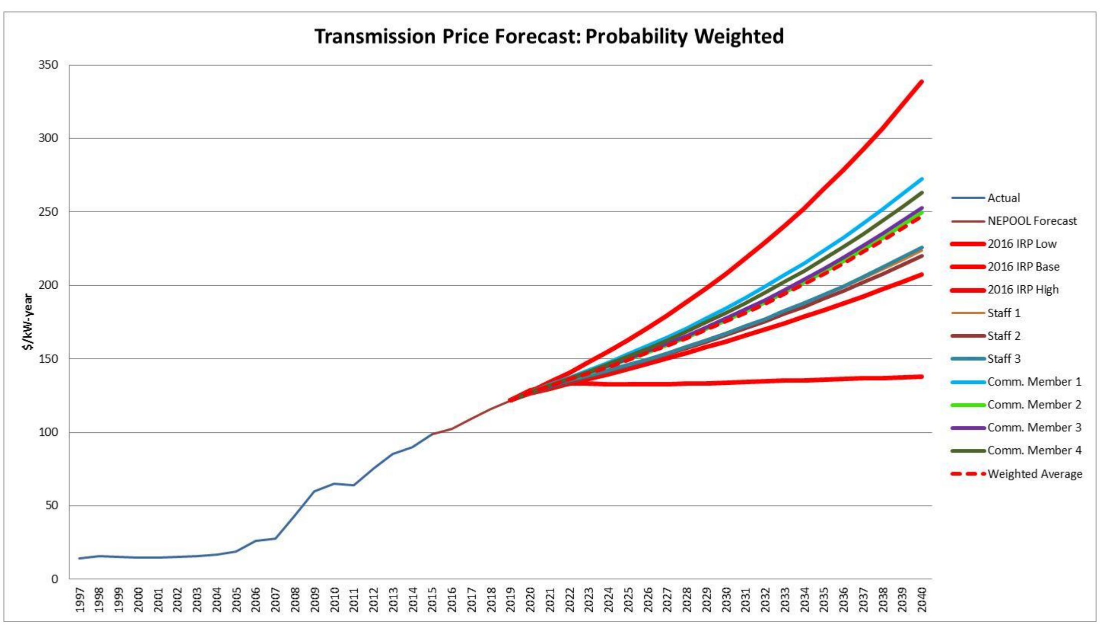
	Transmission Price Probability Assignments		
	High Case	Base Case	Low Case
Staff 1	15%	80%	5%
Staff 2	15%	75%	10%
Staff 3	30%	40%	30%
Committee Member 1	55%	35%	10%
Committee Member 2	40%	45%	15%
Committee Member 3	40%	50%	10%
Committee Member 4	45%	50%	5%
Group Average	**34%**	**54%**	**12%**

Figure 12



The ranges associated with both the high and base cases tend to indicate relatively high uncertainty with regard to the transmission price forecast. For instance, probabilities assigned to the base case range from 35% to 80%. Figure 13 represents the application of the individual transmission price probability assignments as well as the group average to the high, base, and low cases. Due to the low probability assigned to the low case, all the weighted transmission values are between the base case and the high case. The single weighted average transmission price forecast resulting from the group average probability assignment is represented by the dashed red line, which is about half way between the base case and the high case.

Figure 13



The retirement of existing resources and the development of new resources create uncertainty regarding the future demands on the regional transmission system. The potential for new resources geographically separated from load as well as the growth of distributed generation suggest that RNS costs may continue to increase throughout the IRP time horizon. Additionally, statewide goals supporting strategic electrification could increase loads and place new burdens on the transmission system if there is widespread adoption of such things as electric vehicles or cold-climate heat pumps.

REC Price Forecast

Renewable energy credits (RECs) represent the non-energy environmental attributes of a MWh of energy. RECs generated in the ISO-NE region are tradable commodities that are tracked by the NEPOOL Generation Information System (GIS). The type and value of any particular REC is tied to the generating resource that created it as well as the generating resource's age.

BED owns and contracts for resources that produce three types of high value RECs that are actively traded. RECs generated from the McNeil biomass plant qualify as Connecticut Class 1 (CT1) RECs. BED's two contracted wind resources, Georgia Mountain Community Wind and Sheffield Wind, qualify as Class 1 RECs in Massachusetts (MA1), Connecticut (CT1), and Rhode Island (RINew). These RECs are oftentimes referred to as tri-qualified RECs. BED's Winooski One Hydro facility qualifies as a Class 2 non-waste Massachusetts (MA2) REC generator.

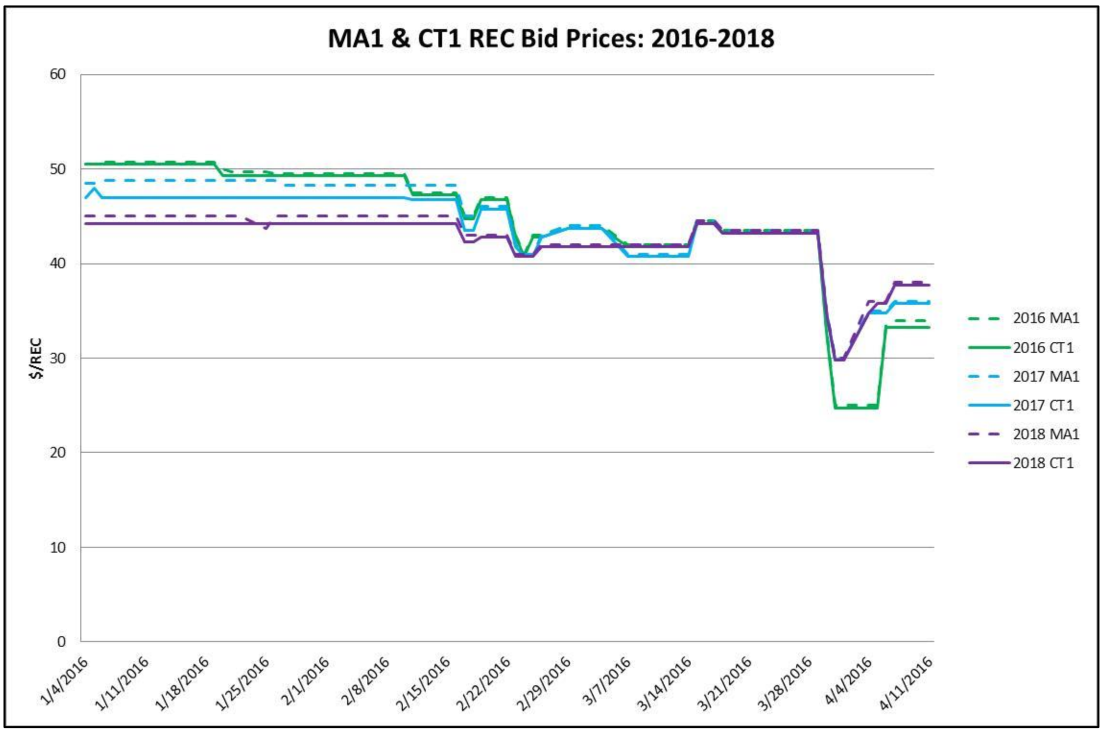
Currently, BED sells high value RECs to generate additional revenues and buys back lower value RECs to maintain its claim of renewability. The net revenues earned from this arbitrage strategy allows for a reduction in costs, thus, generating net positive benefits for all customers. For BED to continue its arbitrage strategy, a price differential between high and low value RECs is essential. For the purposes of forecasting the potential impact of the REC market on BED's cost of service, BED staff focused on whether high value RECs (i.e. CT1, MA1, and MA2) would continue to persist into the future.

MA1 RECs have historically traded higher than CT1 RECs, although more recently MA1 RECs have traded at prices 0-10% higher than the CT1 RECs. The ACP represents the penalty per MWh a load serving entity would have to pay if it failed to have sufficient applicable RECs to meet its load, as set by the state's renewable energy standard. For 2016, the ACPs per MWh of load are: CT1 at $55.00, MA1at $66.99, and MA2 at $27.50.

Base Case

The base case value for CT1 RECs was set at $30.00 and based on historical pricing trends, the MA1 value was set at 10% above CT1 ($33.00). These values are significantly below the current CT1 and MA1 ACPs due to the recent volatility of both markets. Figure 14 shows the bids for CT1 and MA1 that have been made since the beginning of 2016. These values also reflect the downward trend seen in the forward bid and offer prices available from several REC brokers, as shown with the dashed blue and purple lines in Figure 15. The MA2 base case value, due to the tight MA2 market, was set slightly below its ACP of $27.50 at $25.50

Figure 14



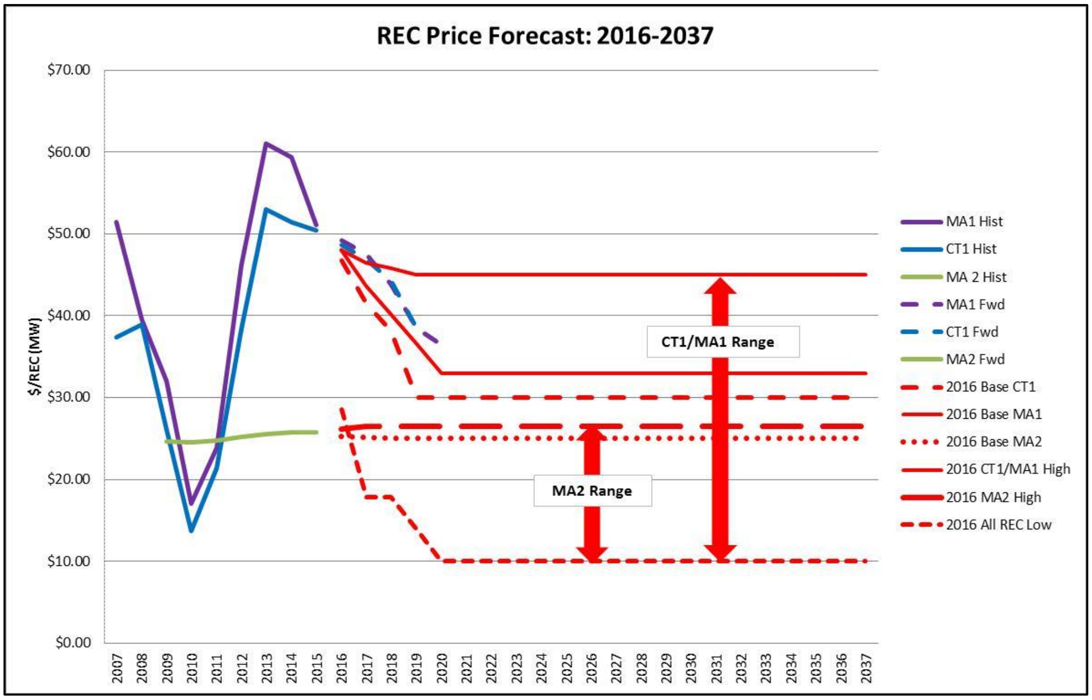
Low Case

For all REC types, the low case value was set at the Vermont Renewable Energy Standard (RES) Tier 1ACP of $10.00, which will go into effect in 2017.

High Case

Based historical pricing trends, CT1 and MA1 RECs were assigned high case values of $45.00. MA2 RECs were assigned a high case value of $26.50, just below its current ACP.

Figure 15



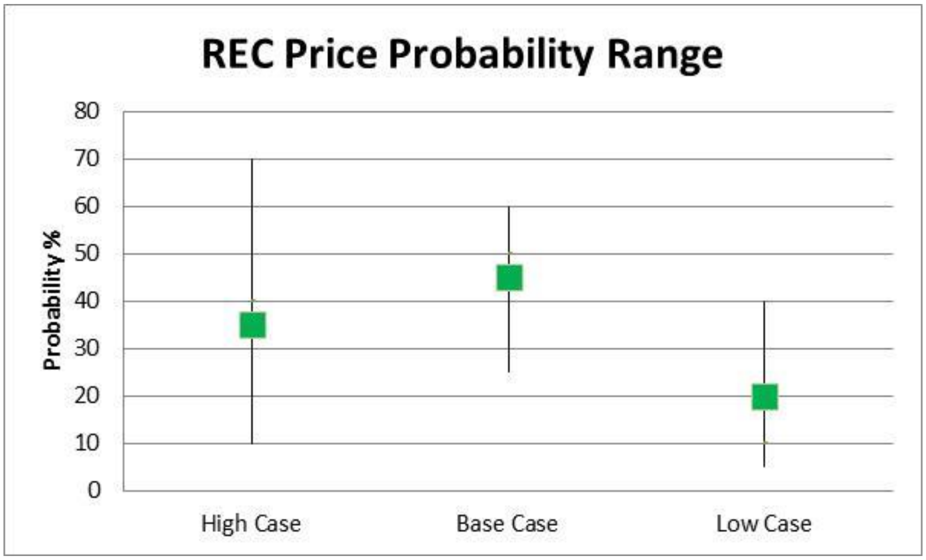
REC Price Probabilities & Weighted Values

Table 5 provides the individual transmission price probability assignments made by staff and the IRP Committee members, as well as the group average. Figure 16 is a visual representation of the range of probability values associated with each transmission price case.

Table 5

	REC Price Probability Assignments		
	High Case	Base Case	Low Case
Staff 1	40%	40%	20%
Staff 2	30%	60%	10%
Staff 3	40%	50%	10%
Committee Member 1	10%	50%	40%
Committee Member 2	15%	50%	35%
Committee Member 3	40%	40%	20%
Committee Member 4	70%	25%	5%
Group Average	**35%**	**45%**	**20%**

Figure 16



The ranges associated with the high case indicate high uncertainty with regard to the REC price forecast. The probabilities assigned to the high case range from 10% to 70%. Figure 17, Figure 18, and

Figure 19 represent the application of the individual REC price probability assignments as well as the group average to the CT1, MA1, MA2 high, base, and low cases, respectively. In all graphs, the single weighted average REC price forecast resulting from the group average probability assignment is represented by the dashed red line. The group weighted average REC value for CT1 was 4% above its base case at $31.25, for MA1 was 1% below its base case at $32.60, and for MA2 was 10% below its base case at $22.53.

Figure 17

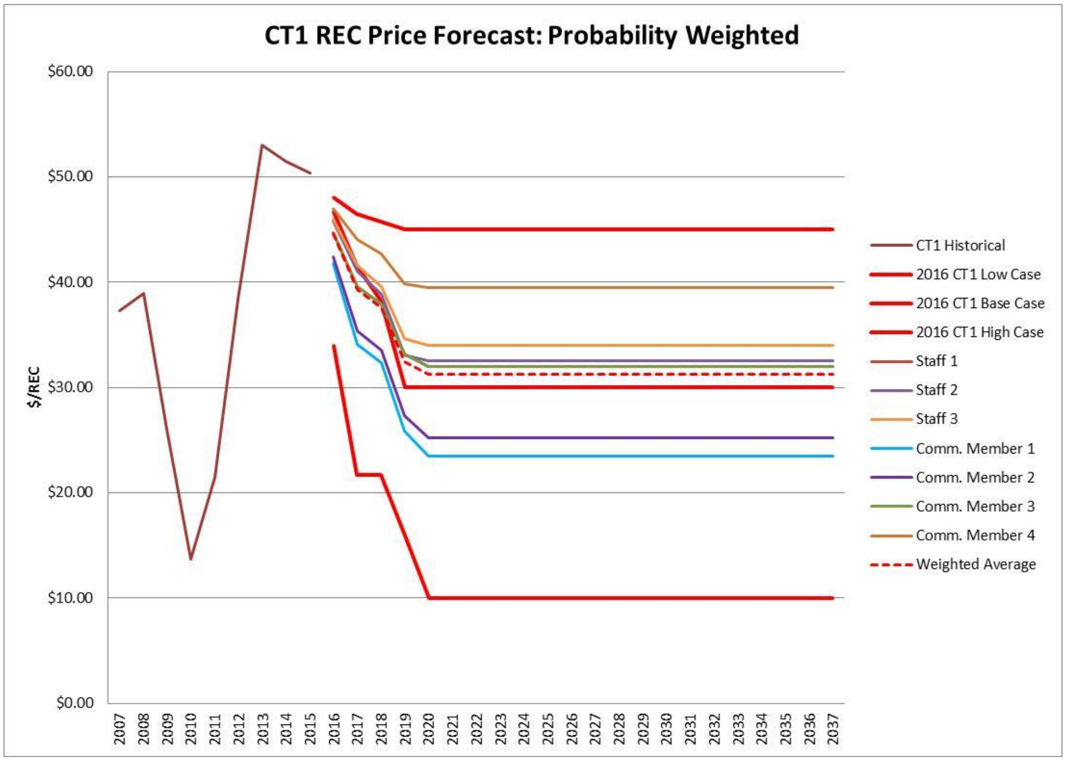
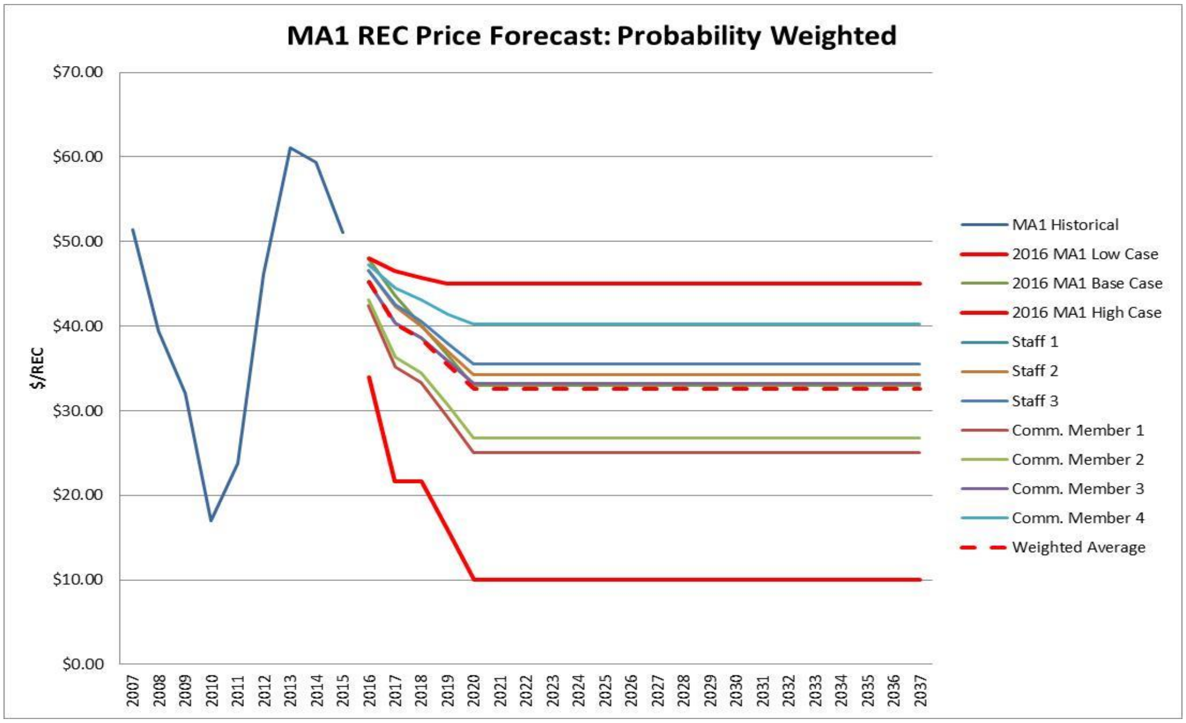
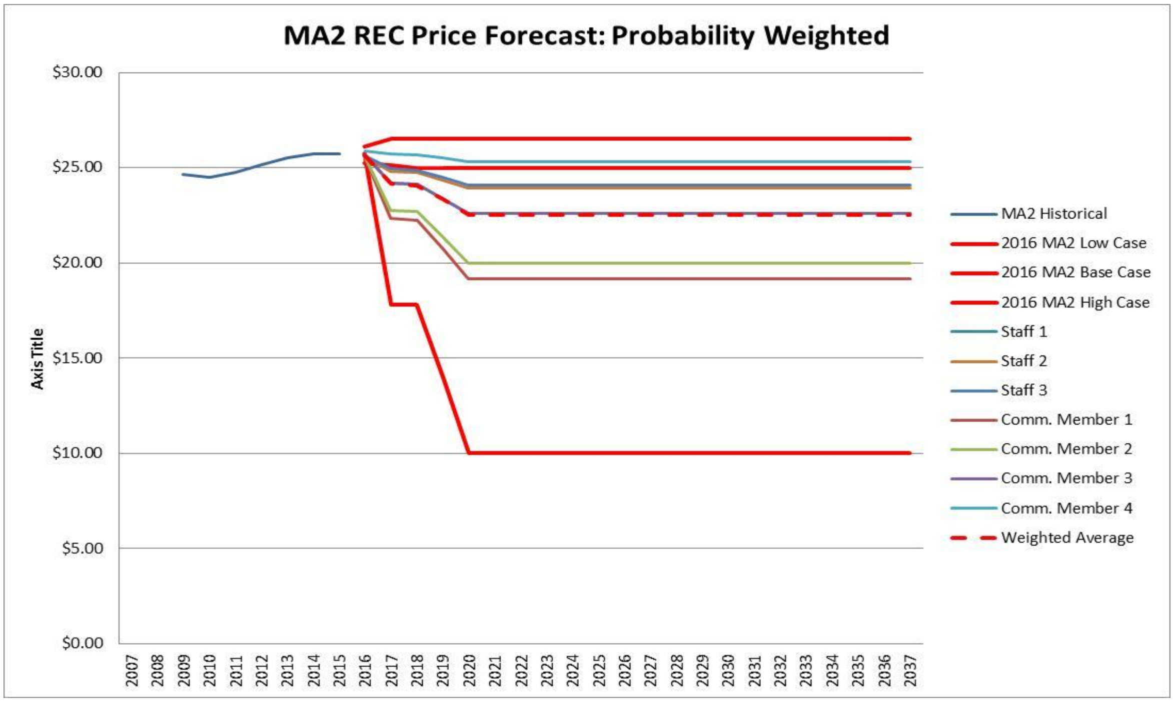

CT1 REC Price Forecast: Probability Weighted
$60.00
$50.00
$40.00
$30.00
$20.00
$10.00
$0.00
$/REC
2007 2008 2009 2010 2011 2012 2013 2014 2015 2016 2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035 2036 2037
CT1 Historical
2016 CT1 Low Case
2016 CT1 Base Case
2016 CT1 High Case
Staff 1
Staff 2
Staff 3
Comm. Member 1
Comm. Member 2
Comm. Member 3
Comm. Member 4
Weighted Average

Figure 18



MA1 REC Price Forecast: Probability Weighted
$70.00
$60.00
$50.00
$40.00
$30.00
$20.00
$10.00
$0.00
$/REC
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
2037
MA1 Historical
2016 MA1 Low Case
2016 MA1 Base Case
2016 MA1 High Case
Staff 1
Staff 2
Staff 3
Comm. Member 1
Comm. Member 2
Comm. Member 3
Comm. Member 4
Weighted Average

Figure 19



REC markets are subject to both market-based volatility as well as the uncertainty that comes with the potential for legislative changes to rapidly change REC values, as shown in the Figures above. The weighted average values for CT1 and MA1 RECs appear reasonable in light of the inherent REC market uncertainty, and appear to be consistent with the increasing state-level renewability targets in New England. BED staff is somewhat less confident that MA2 weighted average prices will hold at current levels throughout the IRP time horizon. Any new supply or generation resource that might be eligible for MA2 RECs will be closely evaluated and its analysis would entail using several MA2 price scenarios.