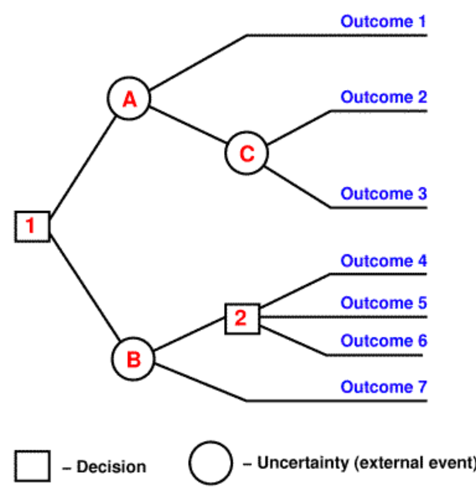
Chapter 7 - Decision Tree analysis

Background

Decision tree analysis is a standard and reliable business tool that has been used by organizations over the past several decades. The tool allows for a systematic processing of several multistage, multi-variate decisions; the outcomes of which could materially impact the operations of an organization. At a basic level, a decision tree is a diagram that represents the decisions to be made, external events that create project uncertainty and the range of plausible outcomes that flow from earlier decisions. Typically, factors that may impose risks on project outcomes are assigned a probability of occurrence between 0 and 1 based on the best available information. By weighting the risks, a reasonable decision path comes into view. In addition to identifying the best-case decision path or preferred decision, decision tree tools provide for greater insight into the range of possible outcomes and magnitude of risks that may impact a project's outcome. In the context of this IRP, risks are synonymous with the variable inputs discussed briefly below. A more detailed explanation of these variable inputs and how they were weighed has been included in Appendix B. This type of analysis is far superior to that contained in early IRP's which only looked at a single set of assumptions with regard to variable outcomes (i.e. a "base case").

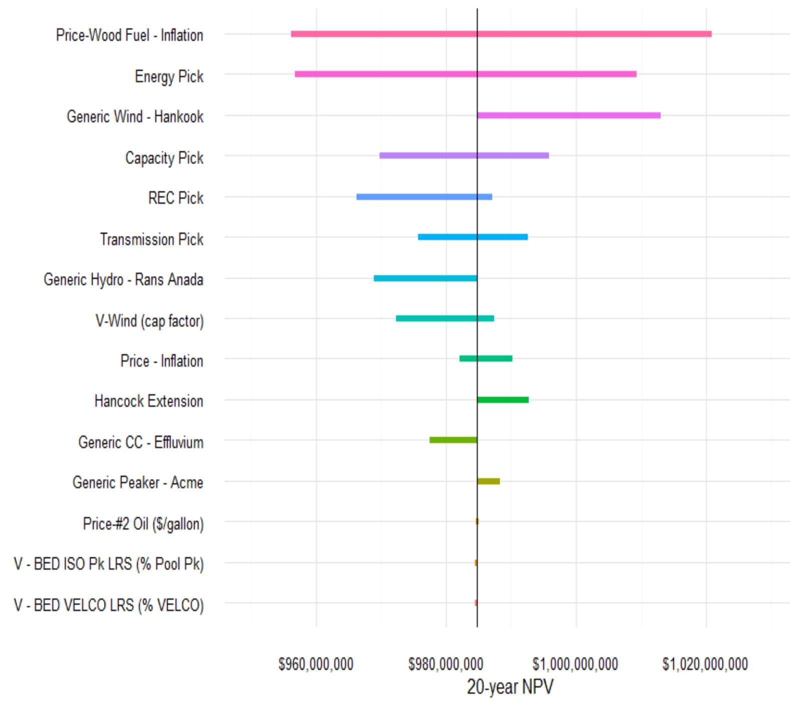


Decision Tree objectives

In accordance with 30 V.S.A. §218c, BED's overall objective is to deliver low-cost, reliable energy services to its customers. At the same time, BED is seeking to maintain its status as a 100 percent renewable provider. Achieving these twin objectives in an uncertain world, however, will be challenging. Multiple known and unknown risks could impede BED's abilities to fully execute its integrated resource plan. Many, if not all, of the known risks are also beyond its control (though risk mitigation options may be available). Complicating matters is the fact that there are undoubtedly several paths that BED could take toward achieving its overall objective. But, the question is, which path has the greatest likelihood of success while shielding BED's customers from as many risks as possible. In short, which of the plausible paths is preferred? BED's primary objective for this stage of the planning process is to identify multiple plausible paths that could be taken, and evaluate them, so that a preferred path could be selected by management.

Decision Tree Analysis Methodology

Known sources of uncertainty (i.e. risks) which could increase the cost to serve customers include, for example, greater than expected inflation, rapid and unexpected increases in natural gas prices, natural gas supply interruptions, lower REC revenues, higher transmission costs, higher capacity costs and the loss of the McNeil power plant. To better understand the potential impacts of these major risks, BED relied on a decision tree framework and conducted several sensitivity analyses. The main point of these analyses was to identify and quantify a range of potential impacts on BED's cost of service that could be attributed to various risks. This was achieved by assigning a range of values for these risks/variables and examining the impact of each on the cost of service at its low, base, and high values. The results are reflected in a series of so-called tornado charts showing the "swing" in the cost of service that each variable can cause depending on its value. The charts, as depicted in the illustrative figure above, list the types of known risks that BED could encounter (vertical axis) and the range of impacts those risks could have on BED's cost of service (horizontal bars). The wider the range of the horizontal bar; the greater the level of risk faced by BED's customers.



For BED, the process (i.e. decision tree framework) leading up to the development and evaluation of the tornado charts followed a series of key steps. These included:

- Identifying, evaluating and modeling input variables;
- Identifying and examining answers to key questions that ensure BED's overall mission is achievable;
- Developing potential decision pathway scenarios;
- Conducting final sensitivity analyses;
- Evaluating decision tree scenario outcomes; and,
- Refining decision tree scenarios and re-evaluating outcomes, if needed.

Input variables

A preliminary assessment of the inputs into BED's decision tree model assumed that the following high-level variables have the greatest potential to impose meaningful impacts on BED's decision making:

- Wholesale energy prices;
- Wholesale capacity prices;
- Regional transmission costs and
- Renewable energy credit prices.

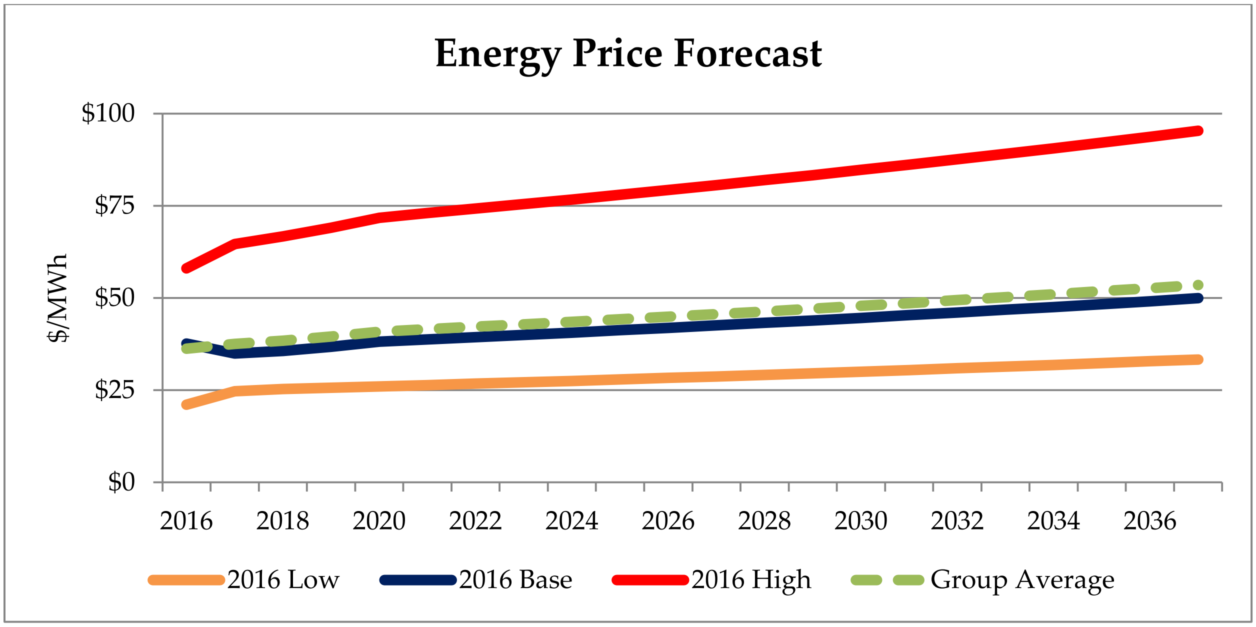
Inflationary impacts: the rate of inflation has the potential to impose the largest financial risk on BED customers; meaning that a higher than expected inflation rate will result in a higher cost of service compared to a lower inflation rate. For the purposes of this IRP, inflation is expected to average 2.5% annually. However, the impact of inflation was not materially different between the decision pathways noted below. Consequently, inflation was not assigned a probability by the IRP committee. Nevertheless, the rate of inflation and the rate of changes to inflation will be continuously monitored, as both could materially impact the net present value of BED's cost of service.

Because these variables could have a significant impact on BED's cost of service, it was necessary to have a better understanding of the range of risks that each one might actually impose on BED's operations as well as the differences between them. For example, if BED elected a course of action (i.e. pathway) that committed it to long term energy requirements equal to 100 percent of load, lower future wholesale energy prices could result in fewer customer benefits in the form of lost opportunities to reduce rates (all other factors being equal) compared to a course of action that allowed for some future spot market purchases. However, committing to long term energy contracts would be a different type of risk (i.e. lost opportunities) compared to the risks associated with volatile RECs prices (i.e. rapid loss in revenues). Thus, both types of risks needed to be evaluated.

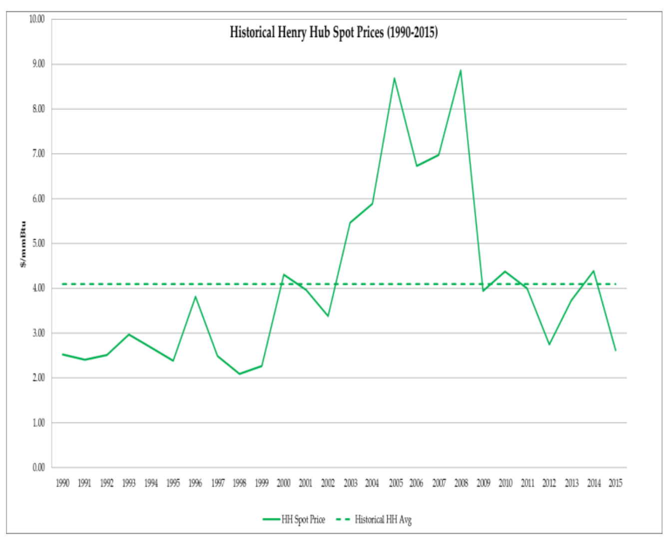
To gain a better understanding of its risks, BED established an IRP committee consisting of 2 members from the Burlington community, 2 Burlington Electric Commissioners and 3 BED staff. The IRP committee met to discuss econometric variables, identify risks and to assign a probability of occurrence to each major risk variable. Based on these assignments, BED staff constructed three price forecast scenarios (i.e. base case, low and high cases) for each variable. The group's averages were then used to establish a fourth scenario – the "consensus" scenario (sometimes referred to as the group average or weighted average). This fourth scenario was, in turn, also used to estimate the future trajectory of wholesale energy prices, wholesale capacity prices, regional transmission costs and renewable energy credits.

The process for assigning probabilities to each of these key variables is discussed at length in Appendix B. However, the outcomes of this process are illustrated in figures 1 through 4, below. The group average line in Figure 1 indicates that BED's decision makers, as a group, would tend to make decisions based on the potential for natural gases to rise slightly from today's levels.

Figure 1: Energy price forecast



Wholesale electric energy prices are influenced by myriad factors, all of which are beyond BED's control. But the single greatest influence on future electric prices is natural gas prices. Between 2000 and 2015, the share of natural gas fueled electric generation in New England has increased from 15 percent to 49 percent, on average. Consequently, natural gas generators have an overwhelming influence on wholesale electric energy prices. Over this same time period, the price of natural gas has also gyrated significantly from a low of $4/mmBTU to a high of $9/mmBTU in 2008. More recently, spot natural gas prices at the Henry Hub gateway are lower, on



average, than they were in 2000; roughly $3/mmBTU.[1] Since natural gas electric generators have increased their market share, they have become the marginal unit of production and thus set wholesale electric prices in New England in the vast majority of hours. This situation is unlikely to change over the IRP time horizon. Longer term, natural gas prices are expected to increase moderately, therefore wholesale electric prices are also expected to rise in a similar manner by roughly 2 to 2.5 percent annually over the IRP time period (which is close to the assumed inflation rate).

While fluctuations in wholesale energy costs are highly correlated with fluctuations in natural gas prices, they are not quite as correlated with BED's net energy costs which need to be passed onto consumers in retail rates. This is so because BED is both a generator and load serving entity. 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 forward capacity payments represent both revenues and costs.[2] For example, BED's generators (i.e. McNeil, Winooski Hydro, etc.) earn revenues when their energy and capacity bids are cleared by ISO – NE. But energy and capacity also represent costs to BED as a load serving entity. All things being equal, higher energy prices typically result in additional revenues for BED as a generator when BED has excess resources. However, higher prices also increase the cost to serve BED's load. If BED has excess energy or capacity resources (long energy and capacity) during periods of high wholesale energy prices and demand, the increased load cost tends to be more than offset by increases in revenue from generation. But, in situations when BED is short on either energy or capacity and needs to purchase additional energy supply at higher prices to serve loads in the City, additional generation revenue is generally insufficient to offset the higher energy costs. So long as BED is able to maintain a balance, in most hours, between generation bids and load commitments, BED's cost to serve load should not be materially affected by ISO – NE's wholesale energy market prices. However, if energy and capacity prices continually rise over time, so too does BED's 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 as both a generator and load serving entity.

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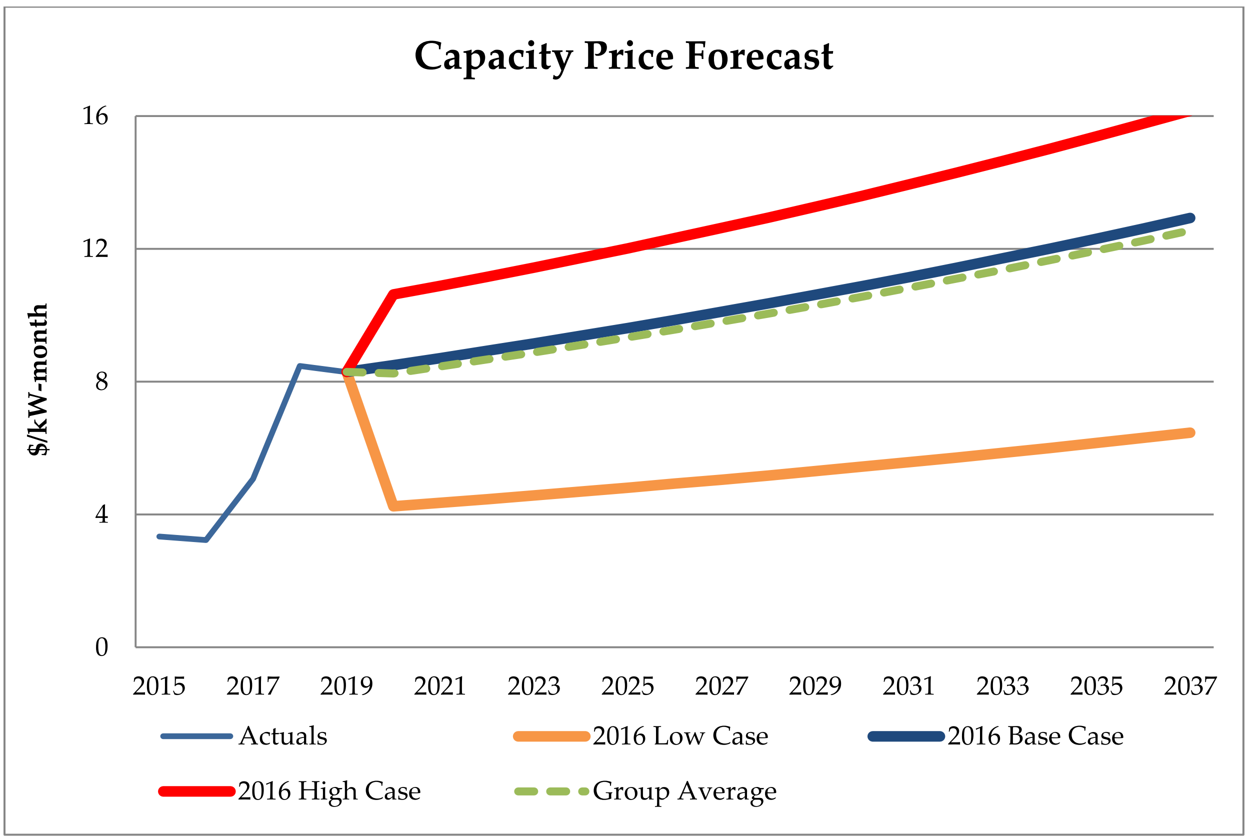
[1] See; https://www.eia.gov/dnav/ng/hist/rngwhhdM.htm - accessed 12/7/2016.

[2] See Appendix B for more detail on Day ahead and Real time energy market rules and practices.

Table 1: Wholesale energy & capacity price impacts on BED's generators and load

	ISO NE Wholesale Prices From BED's dual perspectives	
	High prices	Low prices
Long Energy & Capacity	Benefit (higher net resource revenues)	Cost (lower net resource revenue)
Short Energy & Capacity	Cost (higher net load charges)	Benefit (lower net load charges)

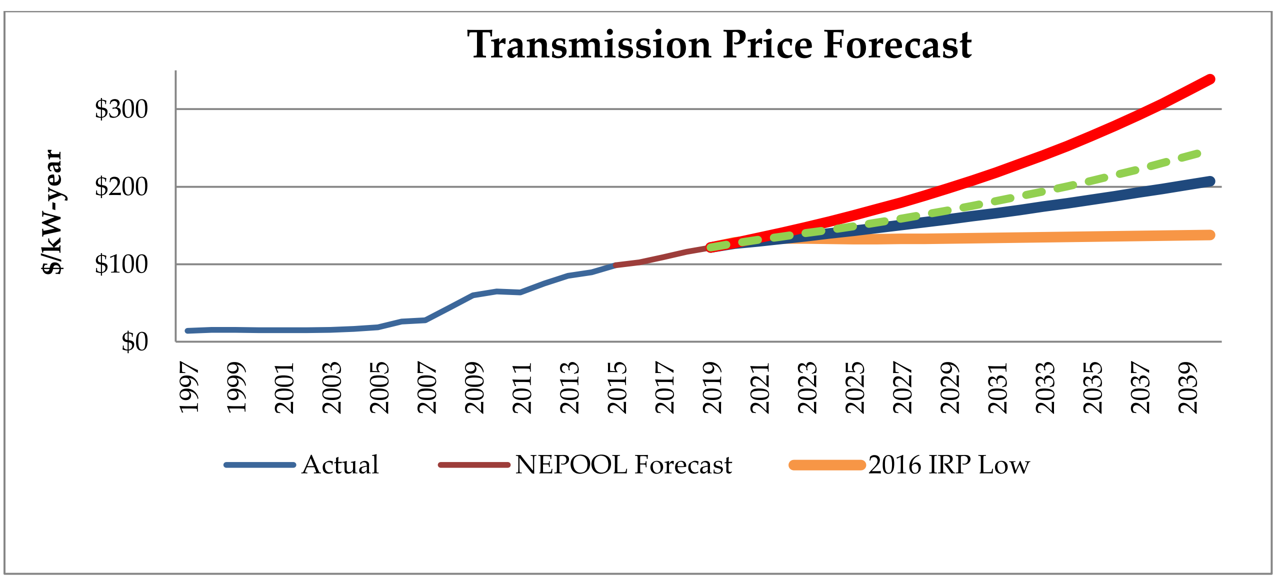
Figure 2: Capacity price forecast



As discussed in the Generation and Supply chapter, BED is capacity short by approximately 35 MWs. A capacity shortfall is not uncommon for Vermont's distribution utilities. Like some other Vermont distribution utilities, BED's capacity situation is a function of its renewability, and the reserve margin (generation above peak load requirements) that ISO-NE needs to maintain for reliability. While its renewable resources may generate sufficient amounts of energy in most hours of the year, the capacity value of BED's renewable resources is de-rated in accordance with ISO-NE's market rules. Thus, BED will need to purchase additional capacity – above and beyond that amount provided from the McNeil plant and the GT turbine. Such capacity purchases will be made during the annual forward capacity auctions. The most recent auction (February 2016) cleared capacity resources at $7.03 per kW-month; a price that is substantially higher from two years ago. Moving forward, BED's IRP committee and Staff expect capacity prices to continue increasing over the IRP horizon. The group average line indicates that as a group, BED's decision makers tend to think that capacity markets will remain "short" and that BED will need new capacity annually. This view of capacity cost increases are primarily a function of the committee's view on fossil-fuel plant retirements. As existing plants are retired over time, new plants will be built. The costs of these new plants are the main determinates of future capacity prices if new capacity is needed. Proposed ISO-NE rule changes with respect to how generators will be paid for performance may also lead to higher capacity costs. As result of these factors, BEDs capacity costs per kW-month are anticipated to increase 62.5 percent (3.125 percent annually) over the IRP time horizon under the weighted average scenario.

However, similar to its energy costs, increases in wholesale capacity costs do not necessarily mean corresponding increases in retail rates. As with energy revenues and costs, BED also earns capacity revenues as a generator as well as incurs capacity costs as a load serving entity. But unlike its energy position, BED will not likely be able to offset higher future capacity costs to serve load with higher capacity revenues since most of its resources are renewable and therefore do not earn significant capacity revenues.

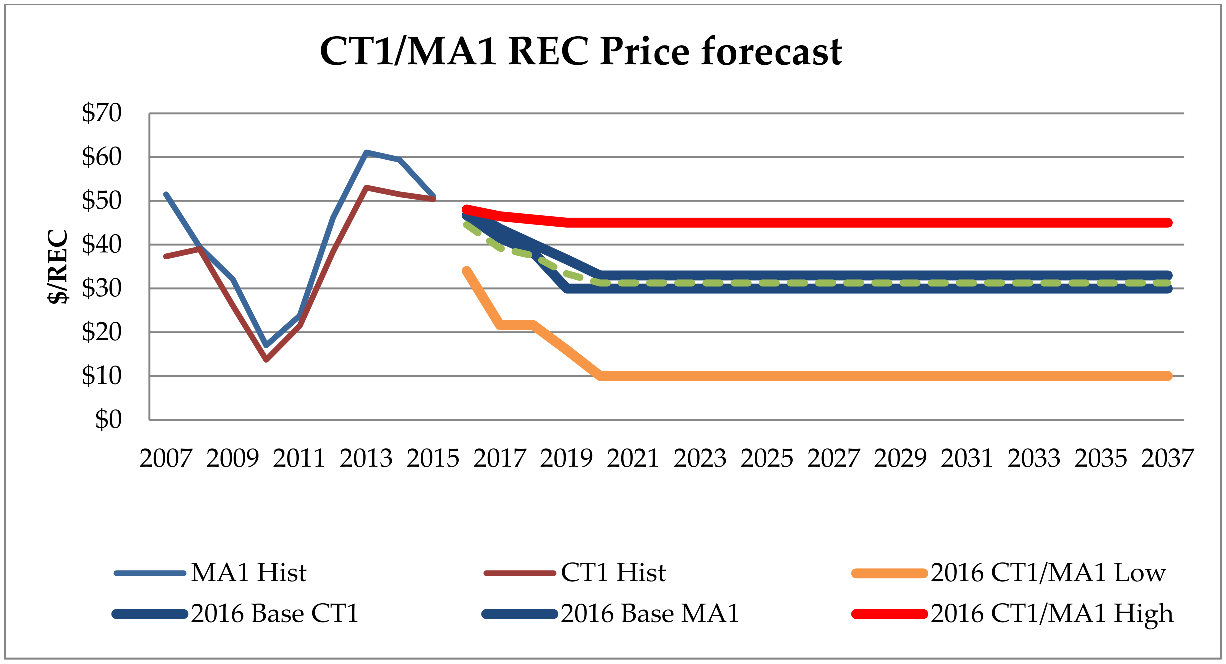
Figure 3: Regional transmission costs



BED pays for transmission services to wheel energy generated from ISO-NE recognized resources, to its customers. Such service is paid under a wholesale tariff, known as the regional network service or RNS, and is regulated by the FERC. Currently, RNS tariff rates are roughly $9 per kW-month. The cost of maintaining the bulk transmission system is socialized among all utilities in New England. Therefore, BED pays a proportional amount of the costs equal to its monthly load requirement that is coincident to Vermont's peak demand for power. Annually, RNS charges currently approximate $6 million. At this time, generation that is settled through the ISO-NE wholesale energy market does not serve to reduce transmission costs (even if this generation may be internal to BED's distribution systems such as the Winooski One plant).

As the graph above illustrates, transmission rates have skyrocketed over the IRP time horizon – from $108 per kW-year to $250 per kW-year. Cost drivers are numerous; ranging from aging infrastructure to more stringent reliability requirements to network congestion to increases in renewable energy portfolio requirements in southern New England. Complicating matters is the fact that avoiding regional transmission costs is unlikely, even in a future world consisting of greater amounts of distributed energy resources. At first glance, increases in DER assets may initially lower RNS charges but overtime such reduced costs will be offset as ISO NE increases transmission rates to recoup its investments. In essence, because maintaining a reliable bulk transmission is of paramount importance and that most transmission costs are socialized across the region, RNS charges are essentially non-by-passable, though they may be shifted between paying entities to some extent. An increase in distributed energy resources will only result in a decrease in future transmission charges (for New England as a whole), if they result is less transmission being built (and perhaps will only serve to curb future increases in transmission costs rather than reduce the costs associated with transmission already constructed).

Figure 4: REC prices



BED owns the rights to sell (or retire) renewable energy credits (REC's[3]) generated from the following resources:

Resource	REC market sales to…..
McNeil	Connecticut - CT1
Georgia Mtn Wind, Sheffield Community Wind, Hancock Wind	Connecticut – CT1, Massachusetts – MA1, RINew
Winooski Hydro	Massachusetts - MA2 (non-waste)

The net proceeds from these REC sales are applied as a reduction in costs; meaning, absent such proceeds BED's cost to serve customers would be higher than it is today. Put another way, when a utility "retires" RECs, it is internalizing the cost of such RECs (i.e. passing those costs on to its customers). REC proceeds are particularly important to the operations of the McNeil plant during this era of exceptionally low natural gas derived wholesale electric energy prices.

[3] 1 REC equals 1 MWh of electricity from qualifying facilities.

BED also buys RECs. To maintain its claim of renewability, BED sells high–value RECs and buys lower value RECs. This arbitrage strategy has recently generated net cash flow of $10 – 12 million annually. The continued success of this strategy naturally depends on a stable REC market that consistently has a generous price differential between so-called high-value RECs (i.e. new renewable solar, wind and other generators, etc.) and low value RECs (i.e.; older hydro facilities, etc.). Such price differentials, however, are not guaranteed into the future. Higher value REC prices are expected to decline over the next few years and could also continue to swing erratically in value as they have in the past. Meanwhile, low-value RECs are not expected to decline much more and may in fact increase with the implementation of the Vermont RES. In fact, the long term price of higher value RECs is uncertain at this point in time, hence the wide disparity between the High Case REC prices (a net benefit) and Low Case REC prices (a net cost), as shown in Figure 4, above.

The price of a REC generally reflects the relative cost of developing certain types of renewable resources (as compared to non-renewable alternatives). But REC price volatility is primarily driven by regulatory uncertainties. Higher REC values stem from regulatory mandates requiring utilities to expand generation from renewable sources or increase the amount of REC purchases. Also, increases in the relative cost of developing new renewable resources exert upward pressure on REC value. On the downside, requirements to purchase more solar power (or RECs) relative to other renewable resources have the effect of depressing the value of McNeil's RECs. Similarly, legislation that reverses previous renewable mandates, or reduces them, would dramatically lower REC prices.

Due to these uncertainties and BED's dependence on REC proceeds based on its past resource decisions, REC values represent the single biggest risk across nearly all of the plausible decision pathways.

As the figures above illustrate, expected price trajectories for each major variable create the amount of risk associated with each variable. Such risks are reflected in the differences between the high case and low case scenarios. As noted elsewhere in this IRP, the greater the gap between these two cases, the greater the amount of risk. Based on the above graphs, energy prices and REC prices appear to present the greatest level of risks under most scenarios.

Any decision path that BED ultimately takes may also be influenced by a myriad of other lower level risks in addition to those discussed above. These risks must also be identified and accurately modelled in order to fully understand how they could impact BED's decisions.

The following 21 variable inputs and risks were also evaluated as part of the decision tree analysis:

Table 2: Input variables

Risk Identifier	Summary description
Price – Wood Fuel	$30/ton for cost of wood at McNeil. The 2017 Budget was used as a base case. The high and low cases are a 10% increase or decrease.
Inflation – Wood Fuel	This is the expected increase per year in cost of Wood to McNeil.
Price – #2 Oil	The cost of oil fuel used in the BED Gas Turbine. Given the low operating hours of the GT this variable is not generally significant
Price – Forward Reserve	The price of Rest of System Forward Reserves in the ISO-NE market. The GT gains revenues from the Forward Reserve Market and BED is charged based on its load.
Price – Inflation	The inflation rate of items not otherwise covered (or forecasted in more detail). This includes all non-power supply expenses.
V – BED ISO Peak	The change in BED's peak relative to the ISO-NE peak. This changes BED capacity requirement in the ISO-NE market.
V – Wind (cap factor)	Wind capacity factor is the projected output of the BED's wind units divided the output if they were constantly running at full capacity.
Transmission Value	Represents expected range in regional transmission rates or RNS tariff. **Originally considered to be a significant input variable but ultimately was not one, as the variance in potential cost impacts was not materially different between decision pathways**. This variable did have an effect in the technology chapter.
REC Value	Represents the expected range of Renewable Energy Credit values in all major REC markets. **This was considered a significant variable.**
Energy Value	Represents the expected range of wholesale electric energy prices. **This was considered a significant variable.**
Capacity Value	Represents the expected range of forward capacity market prices. **This was considered a significant variable.**
V- McNeil Generation (tons/year)	Represents the generation output of McNeil as a function of wood availability.

Load	The non-Extreme Weather load projection.
Load – Extreme Weather	The Extreme Weather load projection.
Peaker Price	The price of a adding a generic Peaker to the BED portfolio in $/MWh.
Wind Price	The price of a adding a generic wind unit to the BED portfolio in $/MWh.
Green Pricing Uptake	The percent of customers volunteering to purchase RECs in a scenario where high-value RECs generated by BED are retired.
DR $/kWh	Price paid per kWh of Demand Response
DR Hours	Number of hours per year of Demand Response called
DR% peak capture	Percentage of capacity peak served by Demand Response asset
V- BED VELCO peak LRS	BEDs load ratio share of VELCO charges

For modelling purposes, the following values were assigned by BED staff to the above listed variables. As noted earlier, probabilities of occurrence for RECs, energy, capacity and transmission were assigned by the IRP committee. For more details on these variables, see Appendix B.

		Input Ranges			% from Base	
Variable	Unit	Low	Base	High	Low %	High %
Price-Wood Fuel ($/ton)	%	90%	100%	110%	-10%	10%
Price-Wood Fuel - Inflation	%	1%	3%	5%	-67%	67%
Price-#2 Oil ($/gallon)	%	90%	100%	150%	-10%	50%
Price - Fwd Rsv Prem. ($/kw-mo)	%	50%	100%	110%	-50%	10%
Price - Inflation	%	2.0%	2.5%	3.5%	-20%	40%
V - BED ISO Pk LRS (% Pool Pk)	%	95%	100%	105%	-5%	5%
V-Wind (cap factor)	%	78%	100%	105%	-22%	5%
Transmission Value	#	Low	Avg.	High		
REC Value	#	Low	Avg.	High		
Energy Value	#	Low	Avg.	High		
Capacity Value	#	Low	Avg.	High		
New Debt Cost	#	5%	5%	6%	-5%	16%

Rate Threshold	#	5%	5%	6%	-10%	10%
Peak Change (MW)	%	95%	100%	105%	-5%	5%
Load	#	Low	Base	High		
Load - Extreme Weather	#	No	No	Yes		
Peaker Pricer	$/MWh	100	130	200	-23%	54%
Wind Price	$/MWh	70	90	110	-22%	22%
Green Pricing Uptake	#	0%	10%	25%	-100%	150%

Examination of key questions

An examination of the potential pathways toward a preferred decision begins and ends with one central question: How likely is it that a decision pathway leads to an outcome that complies with 30 V.S.A. §218c? If the answer is unlikely, then that pathway is eliminated from further examination. For BED, however, the range of decisions must also comport with the City's overarching strategic initiative to become a net zero energy community. Accomplishing this task requires BED to maintain its 100 percent renewability. Thus, additional questions in need of answers are appropriate. These questions include:

With respect to potential energy options; what are the potential impacts on rates and renewability if BED:

1. Entered into additional wind contracts to ensure that its 100 percent renewability remains intact?
2. Extended current contract with Hancock Wind for 15 years?
3. Maintained the status quo for now, while continuing to seek energy options that better fit BED's need?

With respect to potential capacity options; what are the potential impacts on rates and renewability if BED:

4. Built a peaking facility to meet future capacity needs?
5. Re-initiated an active demand response program?
6. Maintained the status quo for now, while continuing to seek new capacity procurements other than purchases in the spot wholesale markets that may better fit BED's need?

With respect to options that preserve its status as a 100 percent renewable provider; what are the potential impacts on rates if BED:

7. Developed a voluntary green pricing program?
8. Continued arbitraging Tier 1 RECs or pay the alternative compliance payment for as long as economically possible?
9. Slowly retired native renewable energy credits?

These nine questions have been categorized into the following case studies:

Energy Case code	Summary description
E1	Additional wind
E2	Extend Hancock Wind
E4	Keep Energy Options Open

Capacity Case code	Summary description
C1	Build Peaker
C2	Keep Capacity Options Open
C3	Active Demand Resources

REC Case code	Summary description
R1	Hard Stop
R2	Arbitrage RECs
R3	Soft landing

Decision pathway scenarios

As a result of the above - noted 9 questions, there were 27 combinations of possible decision pathways that needed to be evaluated. A summary description of the pathways is included in the table below. The light blue shaded pathways are projected to yield the lowest NPV cost of service over the IRP time horizon. These pathways are discussed further below.

Table 3: Plausible Decision pathways

Case Number	Summary Description
E1-C1-R1	Additional Wind - Peaker - Hard Stop
E1-C1-R2	Additional Wind - Peaker - Arbitrage REC
E1-C1-R3	Additional Wind - Peaker - Soft Landing
E1-C2-R1	Additional Wind - Capacity Options Open - Hard Stop
E1-C2-R2	Additional Wind - Capacity Options Open - Arbitrage REC

E1-C2-R3	Additional Wind - Capacity Options Open - Soft Landing
E1-C3-R1	Additional Wind - Demand Response - Hard Stop
E1-C3-R2	Additional Wind - Demand Response - Arbitrage REC
E1-C3-R3	Additional Wind - Demand Response - Soft Landing
E2-C1-R1	Extend Hancock - Peaker - Hard Stop
E2-C1-R2	Extend Hancock - Peaker - Arbitrage REC
E2-C1-R3	Extend Hancock - Peaker - Soft Landing
E2-C2-R1	Extend Hancock - Capacity Options Open - Hard Stop
E2-C2-R2	Extend Hancock - Capacity Options Open - Arbitrage REC
E2-C2-R3	Extend Hancock - Capacity Options Open - Soft Landing
E2-C3-R1	Extend Hancock - Demand Response - Hard Stop
E2-C3-R2	Extend Hancock - Demand Response - Arbitrage REC
E2-C3-R3	Extend Hancock - Demand Response - Soft Landing
E4-C1-R1	Energy Options Open - Peaker - Hard Stop
E4-C1-R2	Energy Options Peaker - Arbitrage REC
E4-C1-R3	Energy Options Open - Peaker - Soft Landing
E4-C2-R1	Energy Options Open - Capacity Options Open - Hard Stop
E4-C2-R2	Energy Options Open - Capacity Options Open - Arbitrage RECs
E4-C2-R3	Energy Options Open - Capacity Options Open - Soft Landing
E4-C3-R1	Energy Options Open - Demand Response - Hard Stop
E4-C3-R2	Energy Options Open - Demand Response - Arbitrage REC
E4-C3-R3	Energy Options Open - Demand Response - Soft Landing

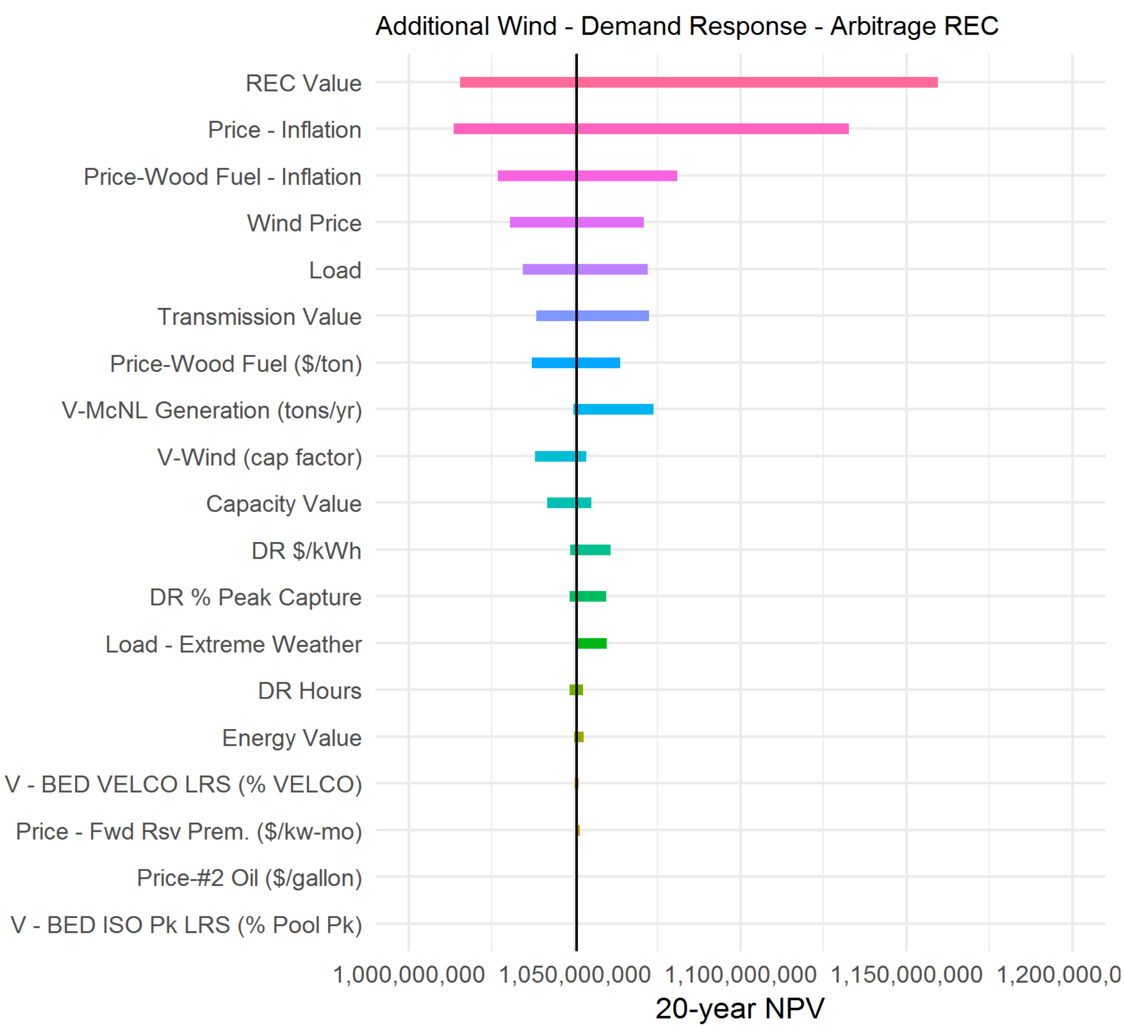
Sensitivity analyses

After compiling the list of 9 case studies, BED began to assess the potential impacts of the above-noted 21 variable inputs on the NPV of the cost of service across each of the 27 plausible decision pathways.[4] As previously noted this was accomplished by conducting sensitivity analyses of the variable inputs and associated risks. The sensitivities reflect the range of potential outcomes for each critical risk as determined by staff, and the weighted average result determined by members of the IRP committee. The results of the analyses are presented in the tornado charts below. The charts illustrate the most significant risks affecting four plausible pathways that resulted in the lowest NPV cost of service. As noted earlier, the longer the

[4] A total of 19 variables are listed in each tornado chart, rather than the original 21 listed above, because certain variables did not produce a wide enough range of risks. As a consequence, those variables were dropped out of the computer outputs as displayed in the tornado charts. While the variables may not have been included in the reported outputs, they were nonetheless evaluated.

horizontal bar; the greater the exposure to that risk. The results of the remaining decision pathways are included in Appendix C.

Figure 5: Decision pathway E1-C3-R2



E1-C3-R2 is referred to as the "Additional Wind – Demand Response – Arbitrage RECs" pathway. Selection of this pathway would result in the lowest NPV cost of service at $1.051 billion over 20 years. As the title implies, this pathway considers the potential risks of assuming additional long term wind contracts along with re-initiating active demand response programs and continuing the current practice of arbitraging RECs. Under this decision pathway, retail rates are expected to increase from $0.17/kWh to $0.25/kWh over the IRP planning period (unadjusted for inflation). Adjusted for inflation (2.5%/ year), nominal retail rates would remain roughly the same in 2036 as they are today – assuming that all other factors remain unchanged.[5]

An active DR program under this pathway, and the others noted below, will include strategies to curtail demand. All rate classes may participate in structures such as voluntary demand reduction through peak time rebates. Residential customer may benefit from automated controls of in-home appliances such as domestic hot water tanks and other similar loads. Other options include combined heat and power, battery storage or fuel cell systems located at the facilities of BED's larger customers. The demand response program challenges include the ability of BED to time a customer's response with the regional peak demand hours and the customer's ability to sustain a power reduction throughout the period of peak demand, which can last multiple hours.

Along this pathway, lower REC price differentials, wind prices, higher than expected loads, and transmission costs impose the greatest risks on BED's customers. REC prices alone could swing the 20-year NPV by $144 Million. Similar to some of the pathways, noted below, the risks associated with RECs are asymmetrical. Lower differentials in REC values with additional wind resources in BED's portfolio would produce approximately $109 million in added NPV costs, while higher differential REC values lower the NPV cost of service by $35 million. Unlike the other major variables, high REC values are a net positive benefit as long as BED continues to arbitrage RECs. REC's produce revenues for BED; which are then applied as an offset to expenses. Thus, all other items being equal, higher REC revenues result in lower overall costs. Under most cases, however, the probability of higher REC values is viewed as lower than the probability of low REC values. Hence, the asymmetric risk profile above.

Higher wind prices could also result in a higher NPV cost of service as BED would have to pass along to its customers the additional cost of wind energy that is not under contract or when a lower cost wind contract expires. For this and other pathways, the price of wind is expected to range from $70/MWh to $110/MWh, as noted above. The risk associated with higher wind prices is roughly symmetrical to the risk of lower wind prices in the future. The price of wind could swing the cost of service by as much as $40 million over 20 years. Thus, if wind prices increase more than expected, the cost of providing service would be $20 million more than the

[5] As noted above, price inflation represents a large risk that will continue to be monitored and managed. Also, wood price inflation could have a material impact on this pathway and others as higher than expected wood fuel costs would materially undermine the cost effectiveness of the McNeil plant. However, these risks affect all of the plausible pathways more or less equally. As a consequence, inflation factors were not a significant influence on BED's choices between major decision pathways.

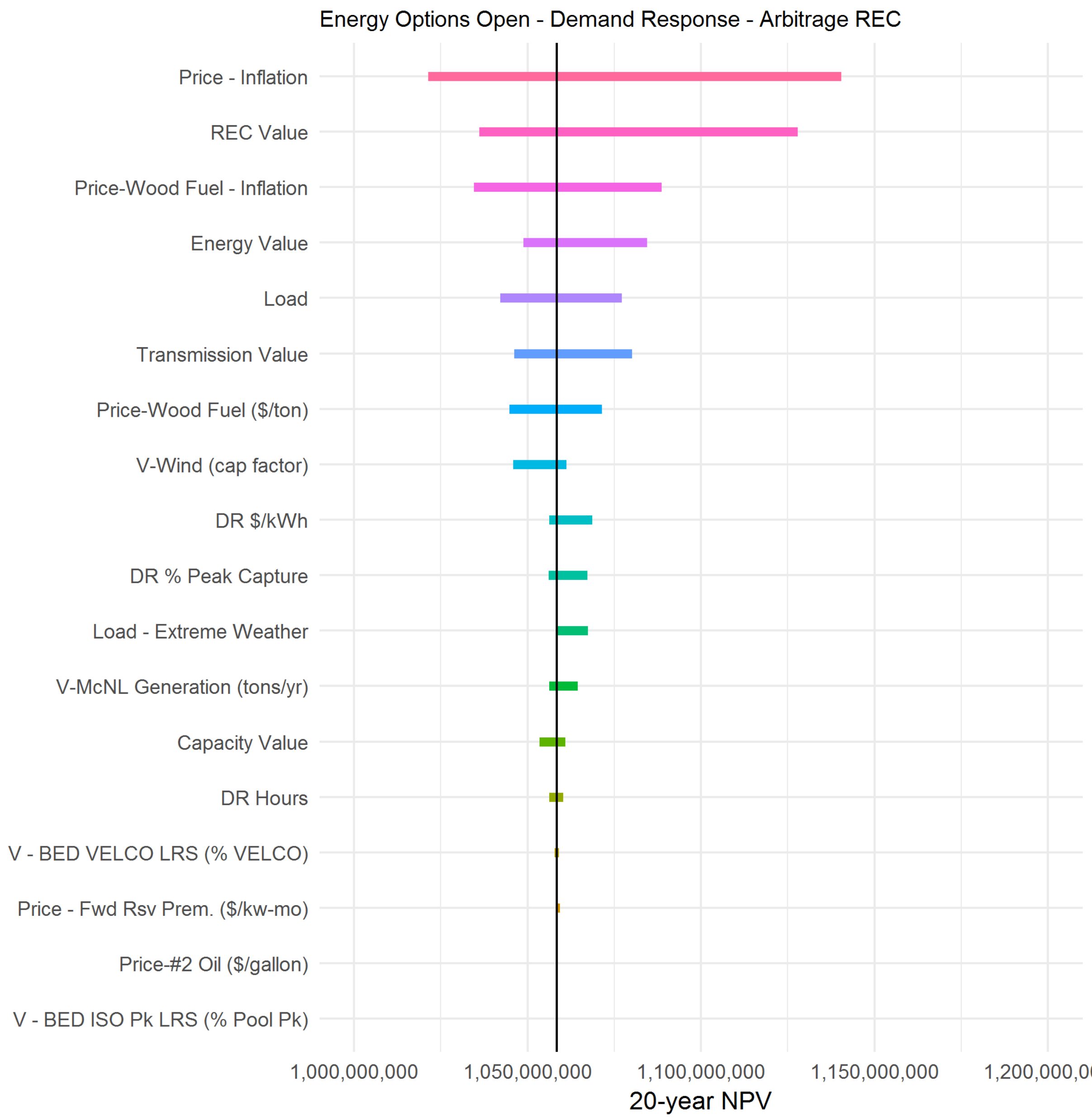
base case scenario. If wind prices decrease more than expected, the cost of service would be $20 million less.

Similarly, higher than expected loads served by BED in the future may increase the NPV cost of service (though in general would not necessarily create rate pressure as increased loads would likewise increase retail revenues). Should overall future yearly loads increase to 425,000 MWhs over the planning period, which is the high case load forecast that includes Tier 3 implications, additional energy over and above the amounts that would be delivered from wind generators under contract would need to be procured. These additional energy purchases are expected to cost more than what could be purchased under BED's wind contracts, and could also be non-renewably sourced. The total swing in the cost of service that is related to higher or lower loads is approximately $37 million over 20 years. Higher than expected loads would drive up the cost of service by $21million relative to the base case; lower loads would reduce costs by $16 million relative to the base case.

Finally, transmission costs will vary over time. The total potential swing in costs could be as much as $34 million over the planning period. As the chart above indicates, the risk of higher transmission costs is considered to be more probable than lower costs. As BED serves more energy loads from ISO-NE settled generation, transmission costs will increase over the time horizon. Higher transmission prices could result in $22 million in added costs relative to the base case; while lower transmission prices reduce costs by $12 million relative to the base case scenario.

As the chart above demonstrates, risks associated with volatile energy prices are lower along this pathway compared to other decision pathways that adopt a "Keep Energy Options Open" plan, such as the decision pathway discussed below. The range of impact on the NPV cost of service that could be caused by volatile energy prices is only $2.9 million. Higher energy prices could increase BEDs cost of service by $2.1 million, while lower energy prices would result in a cost reduction of $0.800 million over 20 years. Reduced risk exposure is a function of having sufficient amounts of new wind added to the resource portfolio as load grows over time or existing energy contracts expire.

Figure 6: Decision pathway E4-C3-R2



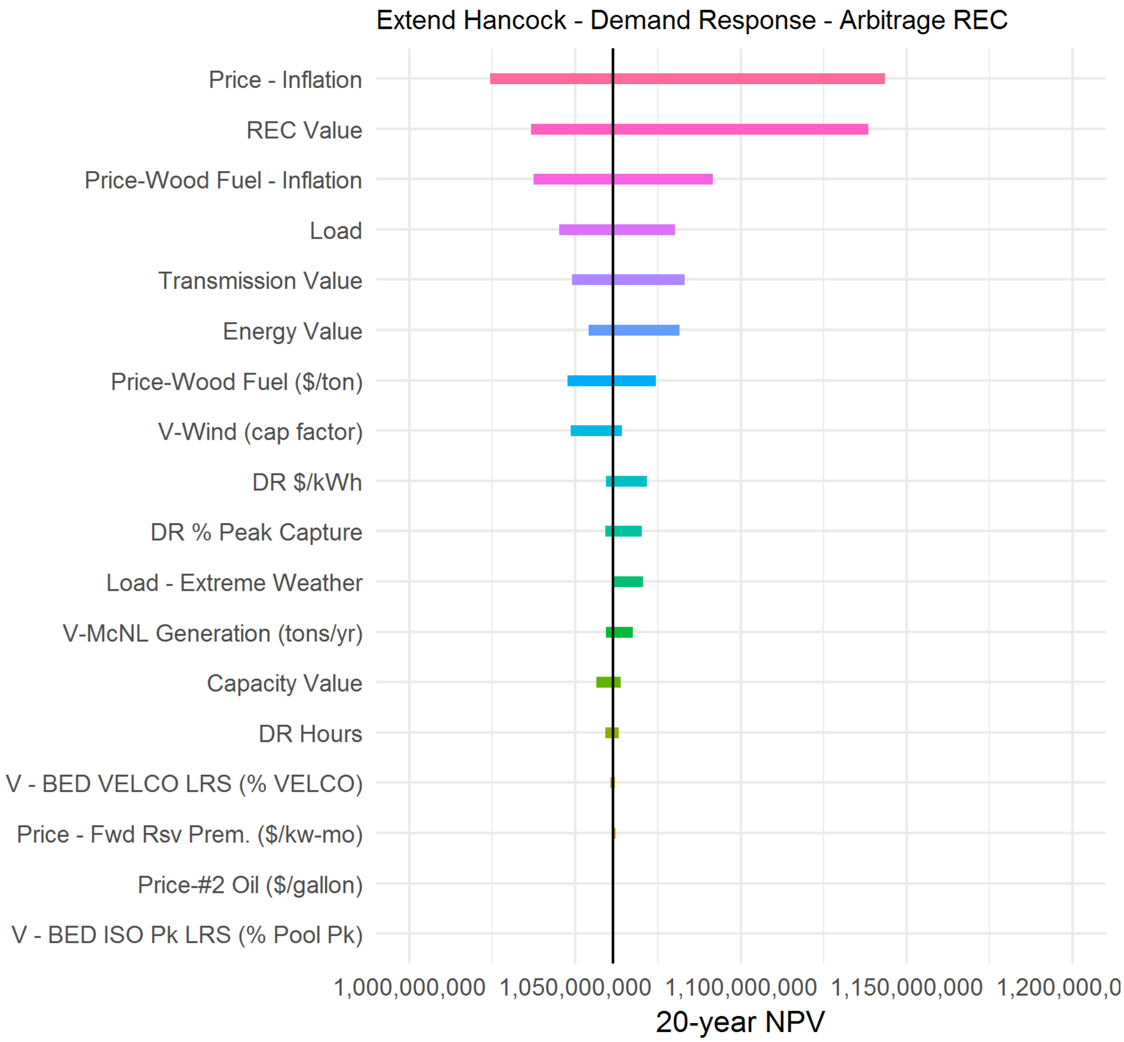
Decision pathway E4-C3-R2 is labelled above as "Keep Energy Options Open – demand response – arbitrage RECs". This pathway results in the second lowest NPV cost of service at $1.058 billion, and could increase average retail rates from $0.175/kWh to over $0.25/kWh (unadjusted for inflation). In many ways, this decision pathway represents the status quo.

Aside from inflation, RECs, energy values and higher than expected load represent the greatest sources of risk. REC values alone could swing the NPV cost of service by as much as $92 million. And, like the previous pathway noted above, the influence of REC prices on costs is asymmetrical. Declines in differential REC values could drive the NPV cost of service up by $70 million, while increased REC differentials would decrease the cost of service by only $22 million. Future energy prices may also impose significant risks and could swing the cost of service by nearly $36 Million (unless other mitigation activities are undertaken). Higher wholesale energy prices would increase the NPV cost of service by $26 million, while lower energy costs would reduce costs by $10 Million.

The third factor that could impact BED's cost of service along this pathway is the amount of load that is expected to be served overtime. In this case, as well as the subsequent cases below, the impact of higher or lower load could swing the NPV cost of service by roughly $35 million. Lower future loads would reduce costs by $16 million, while higher loads would increase costs by $19 million over the planning horizon. As noted above, the swing in NPV costs that is related to changes in load is a function of increasing the expected load to as much as 425,000 MWh annually. Such load growth could stem from strategic electrification programs, higher than expected economic growth, and increases in both new business formations and higher housing starts. While higher loads increase overall costs, they generally do not result in higher rates as the costs to serve new load could be recovered over many more kWhs sold.

In BED's view, this pathway allows for the greatest degree of flexibility over the next several years and keeps a number of options open for consideration. This pathway is discussed in greater detail in the next chapter.

Figure 7: Decision pathway E2-C3-R2

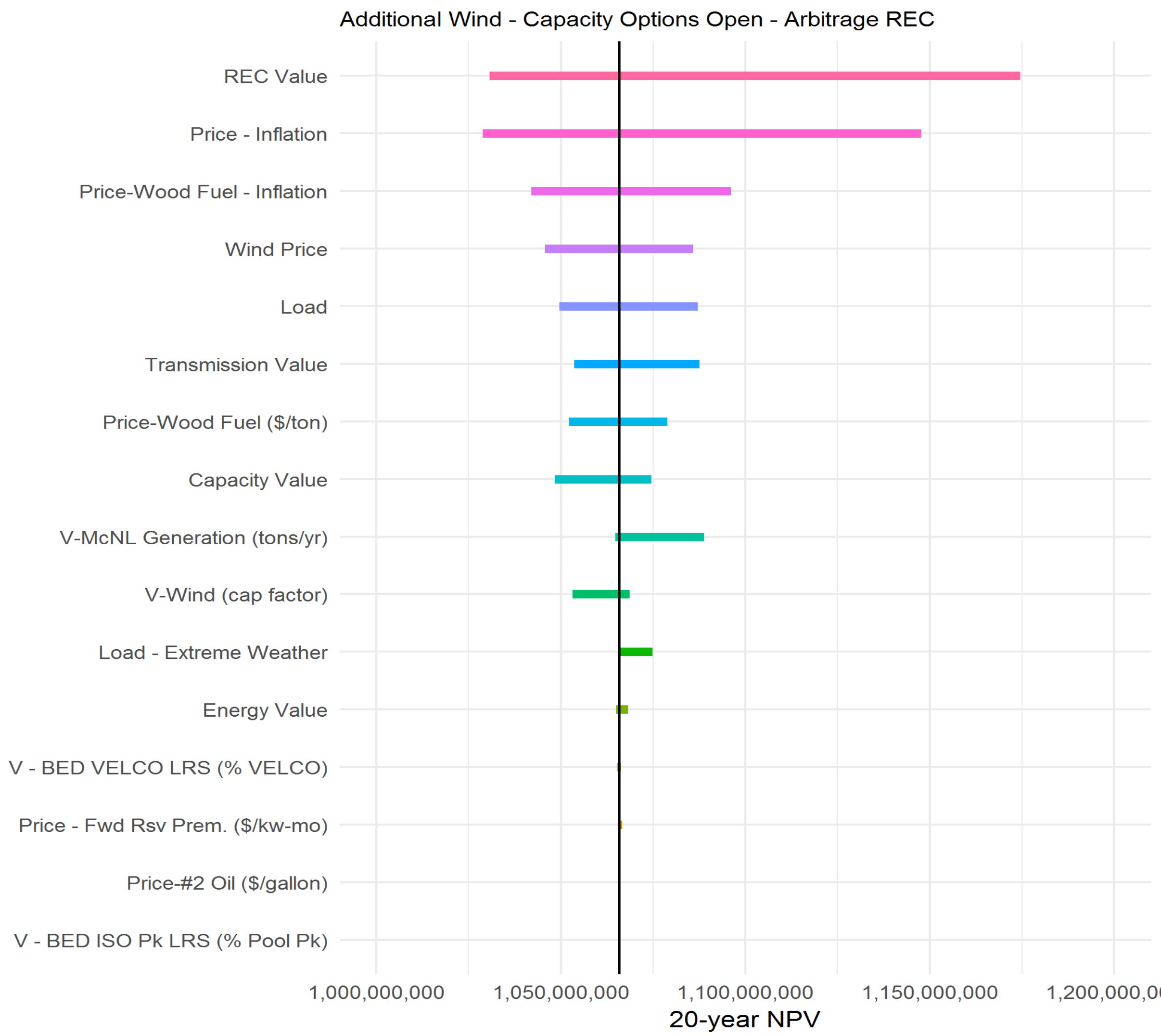


Decision pathway E2-C3-R2, labelled above as "Extend Hancock – Demand response – Arbitrage RECs", is the third lowest NPV cost of service at $1.061 billion. Selection of this pathway is expected to result in similar rate pressures as the two previous rate paths; meaning, rates could increase from $0.175/kWh to $0.25/kWh (unadjusted for inflation).

RECs, higher loads, transmission and energy represent the greatest non-inflation risks under this pathway. REC prices could swing the 20-year NPV cost of service by as much as $102 million. Lower REC values would increase the cost of service by approximately $77 million, while higher REC values would lower costs by $25 million.

As with pathway E1-C3-R2, above, higher loads and transmission prices could also present significant additional risks to BED compared to a decision pathway that did not include new wind resources. Higher than expected loads would increase the cost of service by $19 million; lower load levels decrease costs by $16 million. Also, changes in transmission charges could swing the NPV cost of service by as much as $34 million over 20 years. But similar to previous pathways, this risk is asymmetrical. Higher transmission costs could add roughly $22 million to the cost of service, while lower transmission costs would reduce the NPV costs by $12 million. Similarly, volatile energy prices could swing the cost of service by nearly $27 million. Higher wholesale energy rates could increase the cost of service by $20 million, while lower energy rates reduce costs by $7 Million.

Figure 8: Decision pathway E1-C2-R2



Decision pathway E1-C2-R2 labelled above as “Add wind - Keep Capacity Options Open – arbitrage RECs” is the fourth lowest cost decision pathway at $1.066 billion over 20 years. As with the other selected pathways, the expected impact of the identified risks on retail rates is *de minimus* over time. Also similar to the other pathways, REC values, wind prices, higher than expected loads and transmission prices present the greatest amount of non-inflation risks if BED were to select this pathway. Dissimilar from the other pathways is the risk associated with capacity price fluctuations.

REC values could swing the cost of service by $144 million. Low value RECs may potentially increase net costs by as much as $109 million, while high value RECs would lower net costs by $35 million.

The risk of higher or lower wind prices is symmetrical; higher prices drive costs up by $20 million while lower prices decrease costs by $20 million. However, risks associated with higher loads are asymmetrical in nature. Higher loads would increase costs by $21 million over time; and, lower load values would decrease costs by $16 million.

Because this pathway does not contemplate new capacity purchases, capacity price fluctuations represent an additional risk that is unique to this pathway vis-à-vis the other top four pathways discussed here. Over the 20 year time horizon, an open and unhedged capacity position in a high price market could increase costs by as much as $9 million. This scenario assumes BED is in a capacity short (deficit) position; meaning, revenue from owned generation is insufficient to offset the cost of serving load. But, in a future with low priced capacity, costs could be lowered by $17 million. This scenario also assumes BED is short on capacity in the future. In this case, however, the capacity cost savings to serve load outweigh lower capacity revenues from owned generation.

Similar to the other pathways that add wind resources, the risk of higher transmission costs is asymmetrical. This is so because the IRP committee and BED staff anticipate that higher future transmission prices are more likely to occur than lower transmission prices. Consequently, higher transmission prices could increase BED’s cost of service by roughly $22 million, while lower transmission prices could reduce costs by $12 million.

Like other scenarios that add wind resources to BED’s portfolio, the risk of volatile energy prices is almost entirely mitigated.

Decision path evaluation and results

Based on the above-noted sensitivity analyses, the inputs with the greatest amount of variability across all plausible decision pathways were RECs, energy prices, McNeil generation output, and capacity prices. As noted previously, the risk of higher than expected inflation could be significant but inflation affects almost all 27 pathways in nearly the same way. Consequently, inflation, alone, did not influence any of the choices across the decision pathways. The table below compares the range of risks that individual variables could impose on BED's cost of service across all plausible decision pathways. In this table, the minimum potential impact caused from changes in REC values, for example, along Path E4-C1-R1 (Keep Energy Options Open – peaker – hard stop) is $ 9 million but the maximum impact is $144 million along Path E1-C1-R2 (additional wind – peaker – hard stop). Thus, the difference between these two pathways is $135 million. The impact of changes in REC values for all the remaining decision pathways fall in between these two extreme values. This analysis indicates that based on the ranges assigned to REC prices by BED staff and reviewed by the IRP committee, REC prices are the single, most significant risk that BED will face over time. This analysis also tends to indicate that the initial assumption that RECs, energy costs, and capacity costs are among the most significant risks faced by BED based on current assumptions was correct. Transmission, while originally treated as a significant variable, falls down the list when the generation options that are being considered are ISO-NE recognized (though it was more significant in the technology chapter). The significance of McNeil, in this analysis, is related to its dispatch based on energy and REC price assumptions and staff decided that due to this correlation it did not warrant being revisited for major variable treatment on its own.

Table 4: Minimum, Maximum, and Max- Min Ranges

Max	Min	$Max-$Min	Item
143,919,938	8,978,187	134,941,751	REC Value
40,997,417	2,915,559	38,081,858	Energy Value
24,082,555	988,632	23,093,922	V-McNL Generation (tons/yr)
26,112,490	7,440,930	18,671,559	Capacity Value
22,744,009	15,065,699	7,678,310	Green Pricing Uptake
37,538,498	34,922,481	2,616,017	Load
119,097,195	119,053,385	43,810	Price - Inflation
980,564	978,059	2,505	Price - Fwd Rsv Prem. ($/kw-mo)
9,097,743	9,097,739	4	Load - Extreme Weather
54,128,429	54,128,429	0	Price-Wood Fuel - Inflation
49,873,427	49,873,427	0	Peaker Price
40,295,782	40,295,782	0	Wind Price
33,886,759	33,886,759	0	Transmission Value
26,713,796	26,713,796	0	Price-Wood Fuel ($/ton)
15,394,323	15,394,323	0	V-Wind (cap factor)

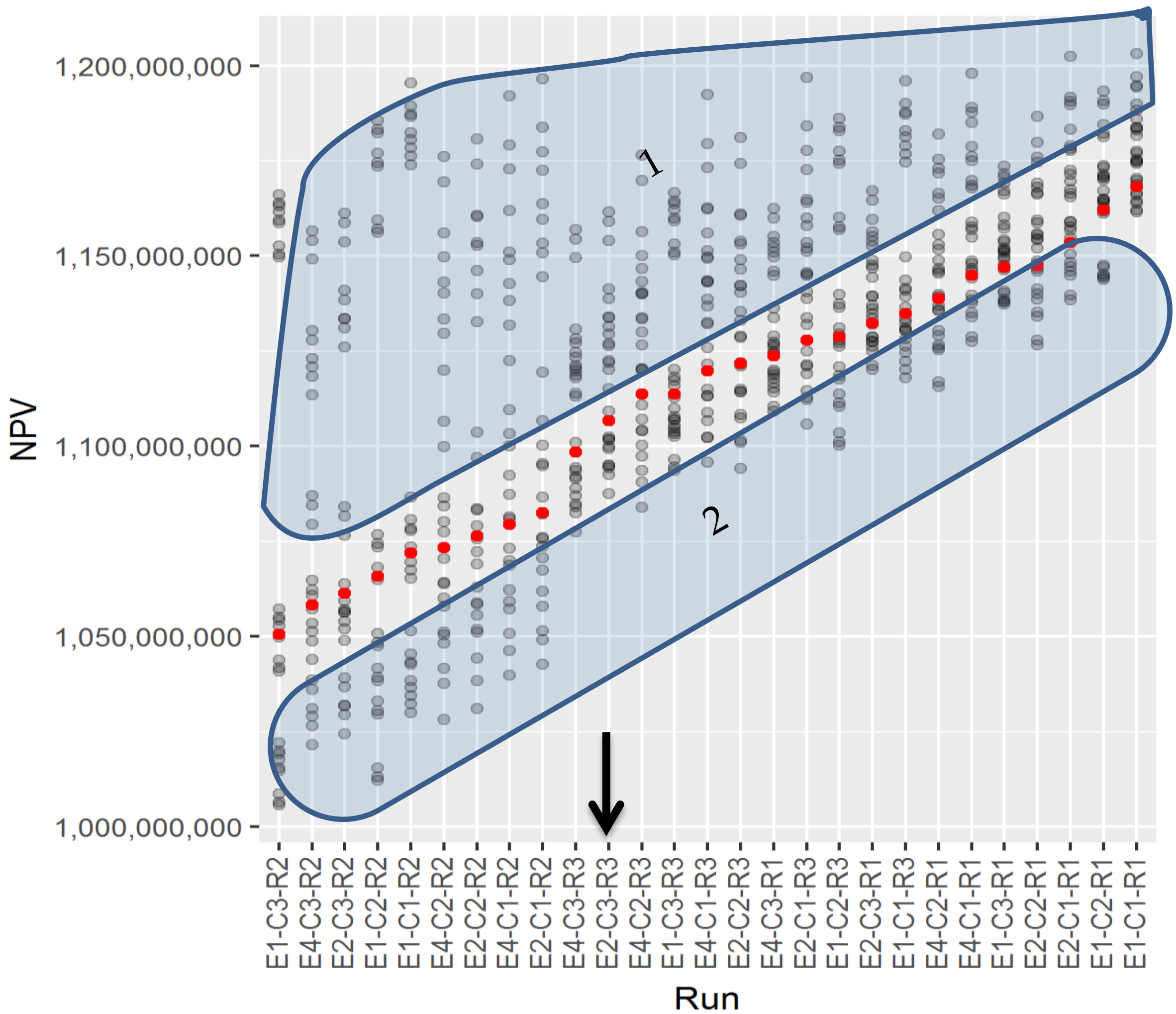
12,279,516	12,279,516	0	DR $/kWh
11,060,339	11,060,339	0	DR % Peak Capture
4,017,970	4,017,970	0	DR Hours
1,199,280	1,199,280	0	V - BED VELCO LRS (% VELCO)
460,428	460,428	0	Price-#2 Oil ($/gallon)
331,467	331,467	0	V - BED ISO Pk LRS (% Pool Pk)

Risks associated with load, energy and capacity price fluctuations have been previously discussed in the above-noted analyses of the top four plausible pathways. Those risks are similar in many respects – but to varying degrees – across all 27 decision pathways. With regard to the risk associated with the McNeil power plant, BED's NPV cost of service could be materially impacted if the volume of generation is significantly reduced. Factors that could reduce production include but are not limited to the availability of ample wood supplies, MWh curtailments due to unplanned or extended outages and unexpected reclassification of McNeil's RECs by another State. Such a reclassification, which is unlikely, could result in a dramatic decline in McNeil's REC value and, thus, reduce BED's arbitrage opportunities as a means of generating revenue.

However, assessing the variability of inputs across all decision pathways fails to inform decision makers about how the aforementioned inputs may affect the NPV cost of service of individual pathways in isolation. In the scatter plot below, each plausible decision pathway is presented along the horizontal axis. The dots in the graph point to the NPV cost of service based on 729 combinations of the inputs for the key variables discussed above.[6]

[6] 729 iterations = 9 case study questions ^ 3 case study categories (base, low and high).

Figure 9: Scatter Plot of variable combinations



The location of each dot along the vertical axes is a direct result of the range of potential outcomes assigned to each variable input, as previously described. This means that the dots shown in area #1 above reflect low REC values, and high values for energy, and capacity and transmission. They also represent higher interest rates, higher wood fuel prices and higher than expected load growth – to name a few of the other variables studied. If all of these factors were to occur at the same time, BED's cost of service would be higher than current expectations. The dots located in area #2 reflect the opposite values. The red dots in the middle of these two areas represent the overall group average weighting for each of the critical values (i.e. RECs, energy, capacity and transmission) and the base value for all the other variables BED Staff evaluated. The red dot NPV values therefore represent the outcomes based on the group's consensus, BED staff expertise and are reflective of the views of BED's decision-makers as a group.

The dispersion of the dots along the vertical axis from the bottom of the graph to the top represents the range of outcomes (or risks) that any one decision path could impose on BED's cost-of-service. The wider the dispersion of the dots; the more risk BED assumes. In general, the lower cost pathways (i.e. those on the far left side of the graph above) appear to have the greatest range of dispersion and, thus, more potential risk compared to the higher NPV cost pathways (i.e. those located in the middle and far right side of the graph above). But not all risks are identical. Some risks can be managed more effectively than others and "risks" of lower cost-of-service results could in fact be viewed as potential benefits. Moreover, reducing risks comes at a cost. In some cases, the high cost of risk mitigation could be imprudent, especially if such costs are extraordinary relative to the actual amount risk exposure.

The least amount of NPV dispersion, as denoted by the black arrow, is decision pathway E2-C3-R3. This pathway represents a gradual reduction in REC arbitrage—sometimes referred to as the "soft landing". Under this pathway, BED would begin to retire its high value RECs rather than sell them. This decision pathway is expected to result in a 20 year NPV cost of service of $1.106 billion; about $55 million more than the least cost pathway referred to as "Additional wind – Demand Response – Arbitrage RECs. Even though this pathway mitigates BED's risks to potentially low REC values, it was not selected as the preferred pathway because of the high NPV cost of this decision over time and its impact on rates. This option essentially reduces the risk of REC price fluctuations by internalizing the above-market costs of renewable resources and raising rates. The trade-off between lower costs and risks is explained in more detail in the next chapter.

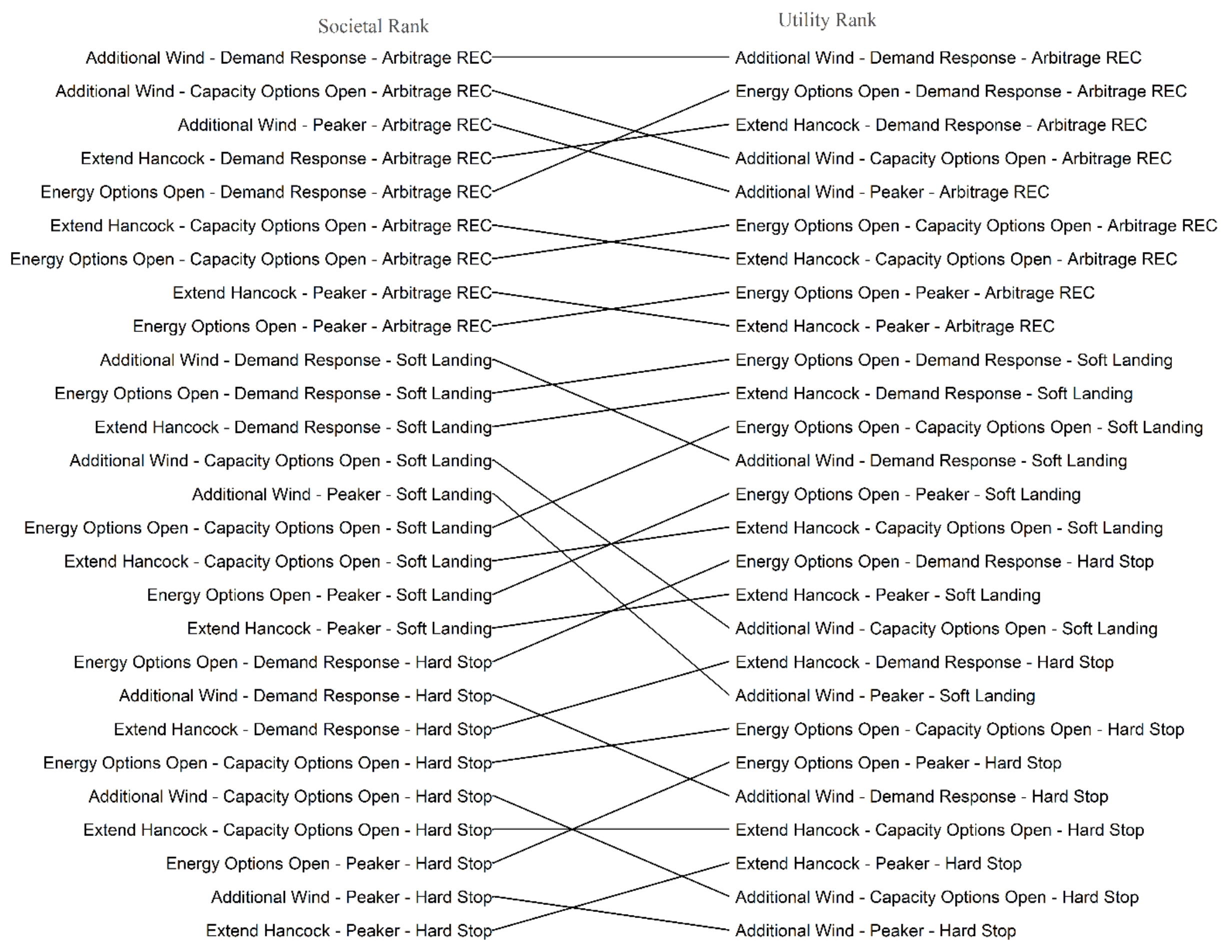
Societal benefits

In yet another analysis, BED compared two sets of decision pathways to each other. One evaluation of the pathways is referred to as the utility test. This set includes all 27 decision pathways that have been discussed in this chapter thus far. The other evaluation is referred to as the societal test. This set of decision pathways is the same as the utility set but for one important difference. When the percent of renewably-sourced energy procured dropped to below 100% of forecasted load in a scenario, a $40.60/MWh carbon adder was applied to those non-renewable MWh's that BED anticipates having to purchase in the DA wholesale markets. The effect of including such an adder was to re-order the pathway rankings listed above (i.e. Tornado charts). In the graph below, each pathway is ranked from least cost to highest cost of service. The societal test evaluation of pathways is located on the left side of the graph; the utility test is on the right. The connecting lines between the two sets show how the carbon adder affected the rankings of the pathways between the two sets.

This analysis demonstrates that the top three utility pathways are roughly interchangeable with the societal set of choices. The least cost utility pathway – Additional wind – Demand response - Arbitrage RECs - is the least cost pathway under the societal test. The second least cost utility pathway – Keep Energy Options Open – Demand Response – Arbitrage RECs – dropped to the fifth least cost pathway under the societal test. And, the third least cost utility pathway – Extend Hancock – Demand Response – Arbitrage RECs – dropped to become the fourth least cost pathway under the societal test. Finally, the fourth least cost utility pathway – Additional wind – Keep Capacity Options Open – Arbitrage RECs – improved to become the second least cost pathway under the societal test.

This comparative test is indicative of BED's efforts to identify plausible pathways that would be in compliance with 30 V.S.A. §218c.

Figure 10: Societal Benefit Matrix



The societal benefit test, noted above, was determined through a multi-step process. First, the $40.60/MWh carbon adder was calculated by multiplying $95 per ton of carbon against the weighted average amount of carbon produced from the so-called "residual mix" of generation. The residual mix represents the unclaimed/non-retired RECs that were generated in 2015, as shown in the table below.[7]

Table 5: Societal Cost $/MWh

Year	Generation	# of unclaimed RECs	Reported CO2 (lbs/MWh)
1Q2015	Residual System Mix	28,197,071	931.6
2Q2015	Residual System Mix	26,904,524	774.1
3Q2015	Residual System Mix	31,798,901	861.9
4Q2015	Residual System Mix	24,825,629	845.4
		Weighted Average lbs.	854.7
		Price of Carbon $/ton	$95
		Societal Cost $/MWh	$40.60

After developing the carbon adder, BED then estimated the additional non-renewable MWhs it anticipates having to purchase in the wholesale DA markets to serve load by year. In doing so, BED assumes, for the purposes of this calculation, that the proxy carbon cost of $95/ton will be the same over the planning horizon. Once future MWh needs have been determined, the carbon adder was multiplied by the non-renewable MWhs needed in each year to reflect the externality costs that fossil fuel generated MWhs would impose on society at large. The table below provides an example of this calculation for decision pathway "E4-C3-R2", the second least cost utility pathway referred to as "Keep Energy Options Open – demand response – arbitrage RECs". For this pathway example, $22.8 million was added to the cost of the pathway under the societal test. Consequently, its ranking dropped from the second least cost under the utility cost test to the fifth least societal cost option.

[7] For additional data, see: https://www1.nepoolgis.com/myModule/rpt/myrpt.asp?r=112

Table 6: Societal cost test example

	Nonrenewable MWh	Societal cost
CY17	-	-
CY18	27,450	1,114,488
CY19	15,455	627,462
CY20	9,254	375,721
CY21	-	-
CY22	34,704	1,408,977
CY23	23,323	946,920
CY24	23,530	955,298
CY25	23,849	968,286
CY26	34,022	1,381,288
CY27	58,187	2,362,375
CY28	59,748	2,425,763
CY29	61,574	2,499,894
CY30	63,627	2,583,266
CY31	66,245	2,689,563
CY32	67,087	2,723,712
CY33	68,601	2,785,206
CY34	79,091	3,211,081
CY35	76,694	3,113,788
CY36	103,285	4,193,374
Total	**$895,726**	**$36,366,461**
NPV		**$22,841,032**

Conclusion

To achieve its twin goals of providing service in compliance with 30 V.S.A §218c and maintaining its 100 percent renewability, BED conducted a comprehensive evaluation of 27 plausible pathways under weighted, base case, high case and low case scenarios. This evaluation provided an assessment of how the net present value cost of BED's service to its customers could be impacted by 729 permutations of variable inputs. Importantly, the analysis provided confidence that the key variables that have the potential to impose large but manageable risks on BED's customers were correctly identified. The risks with the greatest amount of variance between decision pathways were REC values, energy prices, McNeil output, and capacity prices. Although transmission costs are also significant at $33.8 million (2016$), the analysis ultimately determined that exposure to future transmission prices will not likely lead to wide cost variances between most of the decision pathways. However, decisions to add more wind resources to BED's portfolio, could expose BED to some additional risks vis-à-vis decisions that avoided new wind resources, and consequently added wind would drive costs higher if transmission prices increase.

While the decision tree analysis tool is multi-faceted and complex, it allows stakeholders to offer informed input based on relevant data and research. The decision tree framework also provides decision-makers with the confidence that their choices are sound and that they have considered a wide range of risks that could have the greatest potential to impact BED's costs. Most importantly, the decision tool process highlights the least – cost portfolio options. In this analysis, the following decision paths were determined to be the least cost:

Pathway	Total NPV Cost of service (billions)	Range (millions)	Lowest NPV (billions)	Highest NPV (billions)	Path description
E1-C3-R2	1.051	160	1.005	1.166	Add wind - demand response - arbitrage RECs
E4-C3-R2	1.058	134	1.021	1.156	Energy Options open - demand response - arbitrage RECs
E2-C3-R2	1.061	137	1.024	1.161	Extend Hancock wind - demand response - arbitrage RECs
E1-C2-R2	1.066	173	1.012	1.185	Add Wind - demand response - arbitrage RECs

Of the four least cost options, BED's IRP committee and staff selected pathway E4-C3-R2 as the preferred portfolio option to pursue. The rational for selecting this pathway is discussed in the next chapter (though they may be summarized as being related to trading a modest increase in NPV over the lowest NPV, in return for a reduced risk profile, while keeping options open for future resources).