Burlington Electric Department * 585 Pine St. * Burlington VT * 05401

MEMORANDUM

TO: Burlington Board of Finance & City Council

FROM: Kenneth A. Nolan, Manger of Power Resources

DATE: September 5, 2012

RE: 2012 Integrated Resource Plan

Recommendation:

The Burlington City Council approve BED's 2012 Integrated Resource Plan as submitted, and as summarized by staff below.

Background:

Attached is a draft of the Executive Summary from BED's 2012 Integrated Resource Plan (IRP). The IRP is a 20 year planning document and is a state of Vermont statutory requirement. It is designed to assure that consumers are provided with safe and reliable electric service that is balanced with the costs and benefits of providing this service. Key aspects of the IRP include forecasting Burlington's energy needs into the future for 20 years, assessing power supply resources and replacement power strategies including energy efficiency, and carrying out transmission & distribution planning. The following summary is the action plan recommended in the 2012 IRP. The balance of the document is supporting information and discussion.

1. **Continue BED's energy efficiency activities based on the recently approved PSB budget levels and appropriate avoided costs**
   a. Continue to develop an on-the-bill financing tool for electric efficiency measures to encourage participation
   b. Continue to develop a PACE financing program for all fuel energy efficiency and renewable energy measures to encourage participation

2. **Proceed with purchase of Winooski One hydro facility**
   a. Communicate intent to exercise option to Winooski One Partners
   b. Retain expert services in resource valuation and engineering due diligence
   c. Verify cost-effectiveness of any final purchase price using 2012 IRP model processes
   d. Identify most advantageous financing structure and close transaction if economically positive

3. **Increase the level of behind-the-utility-meter solar generation in Burlington**
   a. Conduct an RFP for Solar on Public Buildings
   b. Continue BED Solar Rider – Research TOU,LG,PS Implications of Act 125
   c. Continue entering Purchase Power Agreements for viable projects
   d. Confirm IRP assumptions regarding installed/long-term cost of solar

4. **Maintain BED's existing demand response capability**
   a. Consider expansion of DR capability if this can be done at current rates and from passive load reduction (i.e. no additional backup generation)

5. **Purchase 5 year existing renewable contract**
   a. Execute a contract for 5 years output from existing renewable resource
   b. Consider converting 5 year contract to a rolling five year contract by adding a one year extension annually
   c. During the duration of this agreement (either 5 year or 5 year rolling) monitor energy market conditions for changes in key variables

6. **Continue seeking additional long-term renewable resources to fill remaining supply gap without substantial rate impacts**

7. **Renewability**
   a. When economical, purchase Class II RECs to replace high value RECs sold and be able to demonstrate renewability and increase market pressure for new renewable creation

8. **REC sales**
   a. Continue the existing REC sales hedging program to manage rate impacts from renewable resources
   b. Expand the hedging program to include sale of long term 3-5 year REC strips when prices are advantageous to lock in beneficial outcomes identified in the IRP and minimize the risks identified
   c. Monitor REC markets closely and maintain efforts to preserve value for McNeil, wind, and solar RECs

9. **Other actions**
   a. Monitor legislative activity, particularly as it relates to Renewable Portfolio Standards and allocation of Standard Offer resources to BED
   b. Leverage the new AMI infrastructure to control peak loads and related costs
   c. Gather the data to incorporate electric vehicle impacts and potentials as well as smart meter advances in more detail in BED's next IRP

In order to meet a filing deadline with the Vermont Public Service Board of September 30th, BED is seeking Council approval of the document at the September 24th meeting. Approval of the IRP and the action plan it contains, does not represent pre-approval of specific agreements etc. contained or discussed therein. All final contracts and agreements discussed will be required to conform to the normal Burlington City approval processes.

The information contained in the Integrated Resource Plan document encompasses nearly 200-pages and is quite substantial. BED has attempted to consolidate this information for Council review through this memorandum, and the attached Executive Summary. BED staff will be available at the Council Meeting to answer questions. In the meantime, please feel free to contact me with any questions or concerns that arise as you review the draft.

1 EXECUTIVE SUMMARY

1.1 Introduction and Background

- **Purpose of an IRP**

To meet "…the public's need for energy services, after safety concerns are addressed, at the *lowest present value life cycle cost*, including environmental and economic costs, through a strategy combining investments and expenditures on energy supply, transmission, and distribution capacity, transmission and distribution efficiency, and comprehensive energy efficiency programs."

Key Metrics / Considerations

- 20 Yr PV of Cost of Service
  - IRP is supposed to be "least cost"
  - Rate path – near vs. distant effects
- Environmental Impact
  - Carbon Dioxide Emissions (CO_2)
  - Sustainability/renewability %
- Stability/Predictability vs. Flexibility
- Reliability
- Diversity (Fuel, Location, Etc)
- Credit Risk
- Local/Out-of-state resources
- Considering non-cost metrics in the context of a "least cost" requirement
- Capital Requirements

The Burlington Electric Department (BED) is a department of the City of Burlington that was formed in 1905 to lower the cost of electric power for residences. BED provides electricity in its service territory of approximately 16 square miles, and to the Burlington International Airport, located in South Burlington. BED is the third largest utility in Vermont, accounting for approximately 6.3 percent of Vermont's total retail kilowatt-hour sales. BED currently serves about 16,400 residential accounts, 2,950 small commercial customers, and 828 large commercial customers.

Table 1-1: Vermont Utility Sales - 2010

UTILITY	TYPE	SALES (KWH)	SHARE	CUSTOMERS	SHARE
BARTON	MUNI	14,711,745	0.3%	2,176	0.6%
BURLINGTON	**MUNI**	**350,496,480**	**6.3%**	**20,051**	**5.6%**
CVPS	PRIV	2,201,153,000	39.3%	159,339	44.4%
ENOSBURG FALLS	MUNI	25,113,188	0.4%	1,657	0.0%
GMP	PRIV	1,912,336,000	34.2%	95,150	26.5%
HARDWICK	MUNI	31,472,627	0.6%	4,336	1.2%
HYDE PARK	MUNI	11,611,911	0.2%	1,364	0.4%
JACKSONVILLE	MUNI	5,037,203	0.1%	700	0.2%
JOHNSON	MUNI	14,437,664	0.3%	905	0.3%
LUDLOW	MUNI	48,341,890	0.9%	3,588	1.0%
LYNDONVILLE	MUNI	68,867,673	1.2%	5,578	1.6%
MORRISVILLE	MUNI	44,453,554	0.8%	4,179	1.2%
NORTHFIELD	MUNI	29,301,072	0.5%	2,280	0.6%
ORLEANS	MUNI	12,537,717	0.2%	667	0.2%
READSBORO	MUNI	2,118,366	0.0%	310	0.1%
STOWE	MUNI	73,706,433	1.3%	3,942	1.1%
SWANTON	MUNI	54,687,906	1.0%	3,586	1.0%
VEC	COOP	428,126,762	7.7%	37,616	10.5%
VMPD OMYA	PRIV	196,153,593	3.5%	876	0.2%
WEC	COOP	70,162,421	1.3%	10,552	2.9%
VERMONT TOTAL		**5,594,827,205**		**358,851**	

As a public utility, Burlington Electric Department (BED) is an expression of the community's desires and beliefs. BED offers customers the right to participate directly in the most important decisions about the future of the utility, and as a result has long been a leader across the nation in efforts to promote the not-for-profit utility structure, local control, and sustainability.

As a regulated electric company, BED is required to "prepare and implement a least cost integrated plan (IRP) for the provision of energy services to its Vermont customers," and submit such plans to the PSB and the Vermont Department of Public Service. Id. 30 V.S.A. §218c(b). The objective of the integrated resource planning process is to assure consumers are provided with a safe and reliable service balanced with the costs and benefits of providing this service.

In its 2002 Order reactivating the requirement for utilities to develop IRPs, the Vermont Public Service Board, set a broad objective by stating the following, "...an IRP should include an analysis leading to resource selections whose desirability is robust across a wide range of feasible scenarios, rather than avoided cost analysis seeking to optimize a solution to a narrow range of alternatives". This objective was refined by the Vermont Department of Public Service in which the DPS recommended that scenario analysis be supplemented with an analytical technique known as "decision analysis".

BED believes both the PSB scenario analysis approach and the DPS decision analysis have common elements and each have a common goal of using a systematic thinking approach to problem solving. This IRP continues to build on the decision analysis process used in previous BED IRP's. BED uses decision analysis to help define and quantify a scenario analysis view of its business operations. The two approaches have many elements in common and improve the analytical process of decision making for the future. It should be noted that neither approach suspends the need for common sense, judgment and flexibility. It is important to factor in non-quantified criteria and the consumers' interests rather than focusing entirely on an analytical process and numerical quantification. Lastly, despite the fact that this IRP process has produced a series of conclusions (or "choices"), the IRP process does not absolve utility staff and governing bodies from continually monitoring and challenging the assumptions that led to those choices in the periods between IRPs and before final commitments are made.

1.2 Burlington's Demand for Electricity

Burlington Electric Department's 2012 Long Range Forecast, which provides input to the planning of future resources, focuses in part on the forecasted total annual consumption of electric energy. This is referred to as the system energy forecast and is expressed in terms of kilowatt-hours (kWh), megawatt-hours (MWh), or Gigawatt-hours (GWh). It is made up of forecasts of sales to consumers, company use, and associated distribution and transmission losses, which together make up the electrical energy requirements that must be supplied by generating plants to meet customer needs.

BED's projected load requirements also consider the expected maximum rate of use of electricity (peak demand), measured in kilowatts (kW) or megawatts (MW). The facilities available to the Department must be capable of generating, transmitting, and distributing electricity to meet demand, otherwise loads must be cut back to prevent overloads and/or system failure.

The 2012 Long Range Forecast is a composite of individual forecasts prepared for each of BED's major classes of service. These include residential, commercial/industrial, and street lighting. Estimated losses and company use were added to these forecasts to determine how much energy must be generated (or purchased) to supply sales at the customer meter.

Burlington's annual energy requirements and peak demand forecasts for the years 2011 to 2031 are provided in Table 1-2. The forecast only recognizes the demand-side management (DSM) savings attributable to program activities through the October 2011. The impacts of future utility energy efficiency ("DSM") programs have not been included in Table 1-2.

Table 1-2: Forecast of Annual Energy Requirements & Peak Demand

	2011	2016	2021	2026	2031	Growth Rate 2011-2031
Residential	87,913	89,403	89,706	90,410	92,473	0.25%
Commercial & Industrial	262,164	279,797	308,722	320,686	331,201	1.18%
Street Lighting	4,493	4,548	4,605	4,664	4,723	0.25%
Total Sales (MWh)	354,570	373,748	403,033	415,760	428,397	0.95%
Peak Load (MW)	67.05	71.03	76.52	79.58	81.37	0.97%

Before the effects of future DSM are taken into account, annual use of electric energy is expected to increase by 21 percent between 2011 and 2031, an annual growth rate of 0.95 percent per year. Burlington's system peak demand is projected to increase at a rate of 0.97 percent per year, reaching 81.37 megawatts by 2031. Figures 1-1 and 1-2 provide plots of the projected system peak and energy.

The strongest growth is expected in the commercial and industrial sector, whose sales are projected to increase at 1.18 percent per year. Sales to the residential sector are expected to grow at only 0.25 percent annually, due primarily to higher efficiency standards and slower household formation.

Figure 1-1: System Energy History & Forecast

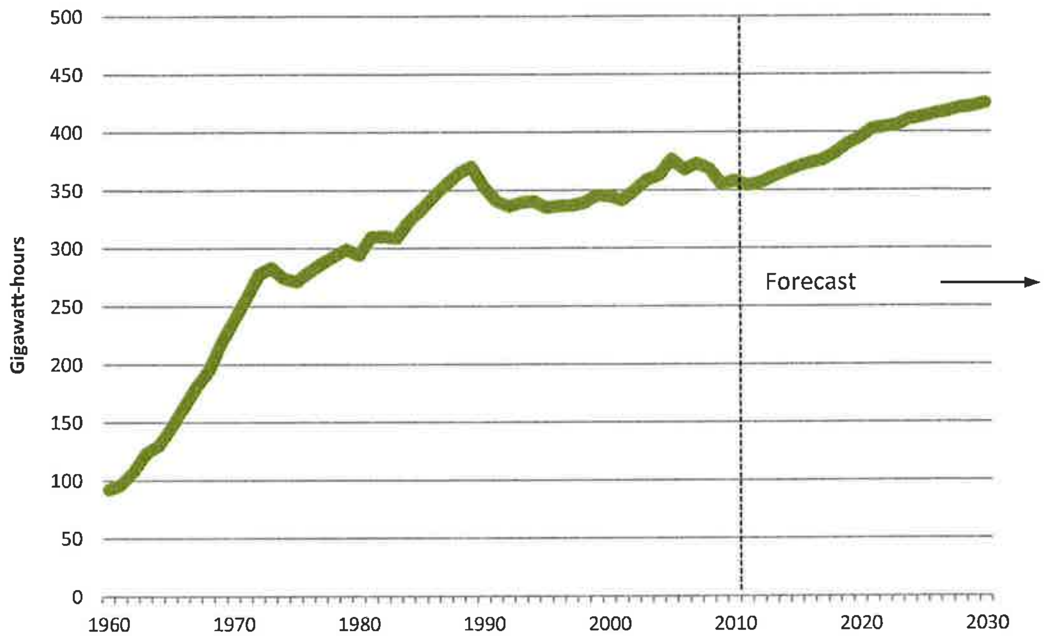
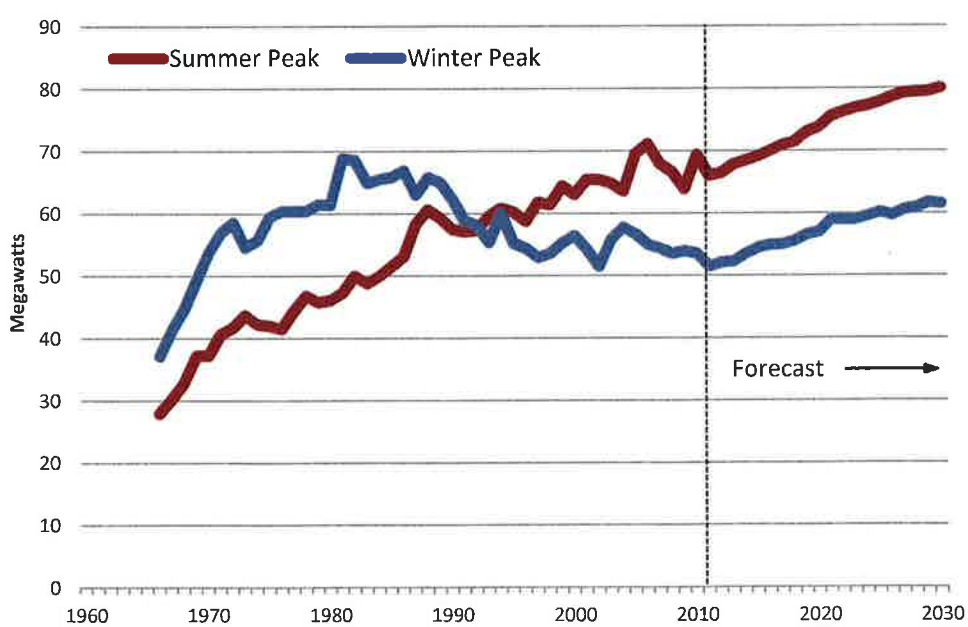


Figure 1-2: System Peak Demand Forecast



1.3 Advanced Metering Infrastructure ("AMI") Changes

BED partnered with other Vermont utilities and the DPS to develop and submit a statewide grant application to the Department of Energy ("DOE") to obtain Smart Grid Investment Grant ("SGIG") funding. The funds awarded to all participating Vermont utilities totaled $69 million of a $138 million project (100% of the requested amount). DOE awarded BED $7.15 million for a $14.3 million total project (again 100% of the requested amount). The full Federal matching funding received by BED reduced BED's direct cost for its smart grid projects by 50% and resulted in the AMI business case having slightly better than breakeven economics. In addition, BED recognized that if AMI became mandated in the future (or if it became clear that demand savings were greater than BED projected) when federal funding was not available, the full costs would have to be borne by BED's customers. Accordingly, proceeding with an AMI deployment became advisable.

One major component of the project is converting all of BED's old mechanical meters to advanced electronic meters (except where customers have indicated that they do not wish this conversion to take place, i.e. "opted-out") and improving BED's back-office systems to manage the newly provided data (the other major component is upgrading BED's Supervisory Control and Data Acquisition ("SCADA") system).

A more detailed discussion of the AMI changes appears in Sections 4 (Trans. & Distr.).

1.4 Transmission and Distribution

BED is physically connected to Green Mountain Power (GMP) through the McNeil Plant Substation, and to the rest of Vermont through the Vermont Electric Power Company (VELCO) at the East Avenue and Queen City Substations. In addition, BED serves load at the Burlington International Airport, which is located in GMP's service territory, and for which BED purchases transmission service from GMP to transmit resources to these customers. These connections allow BED to purchase power from virtually every utility in the northeastern United States and the eastern half of Canada, including Ontario. However, BED has given preference, where practical and economic, to purchasing resources located close to its load, within Burlington, then in Vermont, and then in the rest of New England and other regions being the general order of preference.

BED's sub-transmission system includes approximately 1.5 miles 34.5 KV line jointly owned between BED (40 MW) and GMP (20 MW). The distribution system throughout the City is comprised of 4.16 KV and 13.8 KV voltage levels. BED has 25 MW of on-system generation in the Burlington Gas Turbine, which is connected directly to the 13.8 KV distribution system. In addition, the Winooski One hydro-electric generating facility is also internal to BED's system. Winooski One currently provides power to all Vermont utilities under a state PURPA contract; however this contract ends in March 2013 and BED has a right to purchase the facility at that time at fair market value.

BED has several programs in place to increase the efficiency of the distribution system. As a result, BED's total Distribution System losses have dropped from 3.96 % in 1996 to 2.20 % in 2011 (this represents an additional reduction from the 2.6% for 2007 that was reported in BED's 2008 IRP). These programs include: converting BED's 4.16 KV circuits to 13.8 KV, creating new distribution circuits, retirement of 4.16 KV substations, equipment acquisition standards, the optimum placement of capacitors, load balancing among circuits, strategic placement of circuit null points, and phase balancing.

BED has instituted programs to continually improve system reliability and to provide its customers with the highest reliability that is economically feasible. To improve the reliability of the supply sources and the distribution system, BED has relocated its interconnection with Green Mountain Power from the Lake Street Substation to the McNeil Plant Substation and constructed approximately 1.5 miles 34.5 KV sub-transmission line between East Avenue Substation and McNeil plant Substation as part of the East Avenue Loop (EAL) project. BED has continued its tree trimming program, continued to install animal guards on its 13.8 KV distribution circuits, and installed circuit reclosing devices. BED is converting the remaining old 4.16 KV circuits to 13.8 KV, and will continue to replace its old underground system with new cables, conduit systems and equipment.

As a portion of its DOE grant, BED Operations is replacing the radio system with a new Ethernet network using a fiber optic cable backbone to transmit data between BED operations and BED's field devices. The network will be BED owned and maintained so payment of a monthly fee will no longer be required and when an outage occurs on the fiber, BED will no longer have to wait for the owner to repair the damage. Because fiber is a highly secure transmission medium and SCADA will be on its own private network, BED will be able to comply with the strict federal cyber security standards designed to protect the electrical grid and its reliability.

The SCADA system will be completely upgraded to the latest software version along with a long overdue hardware replacement. Many old RTUs will be replaced with new ones that will be compatible with the new fiber optic network and also offer more monitoring capabilities at each device. One of the biggest benefits to this upgrade is the upgrade of the system control capabilities both at BED's primary location and at a back up operations center at a secondary location (in case the Pine Street facility would become incapacitated) allowing BED to operate the grid in an emergency.

1.5 Demand Side Management

Burlington voters in 1990 approved an $11.3 million bond to fund energy efficiency programs that supported successful program activities through 2002. Since 2003, BED customers (like all other Vermont electric customers) pay a small monthly charge that supports these continued "Energy Efficiency Utility" programs. When these funding sources are considered along with customers' direct investment, $38.3 million has been invested in energy efficiency efforts sponsored by BED over the last 22 years. This is comprised of about $17.6 million spent by BED on all of its energy efficiency efforts during that period, combined with another $20.7 million in matching expenditures by its customers.

The willingness to invest their private funds in these investments is a testament to the value that BED customers place on these services. As wholesale restructuring took effect across the United States, and utilities outside of Vermont began to divest their generation and load assets, the PSB realized that a new mechanism for delivering cost effective DSM programs was required. In response, the PSB instituted statewide "core" DSM programs that are operated under contract by a non-profit, non-utility service provider named "Efficiency Vermont" (EVT). Due in large part to its history of active and cost effective energy efficiency efforts, BED was authorized to continue delivering the core programs within its service territory, and to continue building on its past success in helping Burlington's customer-owners achieve efficient electric use. BED presently provides the following DSM programs within its territory: Commercial and Industrial

Market Opportunities Program (MOP), Commercial and Industrial New Construction Program, Residential New Construction Program (Vermont Energy Star Homes), Efficient Products Program, Low-Income Multifamily Residential Energy Efficiency Program (REEP), Low-Income Single-Family Program, and the Residential Existing Homes Program. BED is the only Vermont distribution utility (i.e. a utility responsible for selling electricity to end-users) that still provides these services to its customers directly. Customers in the remaining Vermont utility territories are served by EVT. BED coordinates efforts with EVT where programs span geographic boundaries.

During 2011 alone, BED saved 8,239 Megawatt hours (MWh) of energy from efficiency measures installed, which will result in 70,900 MWh of savings over the useful life of the installed measures (2011 measures have a weighted average lifetime of 9 years). This is equivalent to providing energy to about 1,560 average Burlington residential customers for 9 years. During 2011, total BED program spending was $2,061,883 and participating customers spent an additional $1,020,850 of their own to fund energy efficiency investments in their homes and facilities.

In proceedings that occurred outside the context of this IRP, the Vermont Public Service Board set energy efficiency budgets and targets for BED for the approximate period between this IRP and when the next IRP will be due. This represented a different situation than prevailed in the prior IRP where the level of appropriate DSM (energy efficiency) expenditure was being determined. To reflect this change, BED staff treated the projected level of DSM savings per dollar spent as a variable and tested the impact changes in this variable had on its conclusions. BED continues to view the value of energy efficiency as a tool for lowering consumer costs and the Department's long-term power supply costs. BED remains committed to offering its customers high-quality and affordable services and a secure, environmentally sound supply of future electricity. Energy efficiency continues to play a major role in achieving this goal.

Additional information provided by the advanced metering being deployed this year should allow BED's energy efficiency staff to better assist customers who contact BED for help in controlling their energy costs. Information from AMI meters will allow a much greater understanding of how and when customers use electricity and what potential for savings may exist at a specific locations.

1.6 Resource Analysis

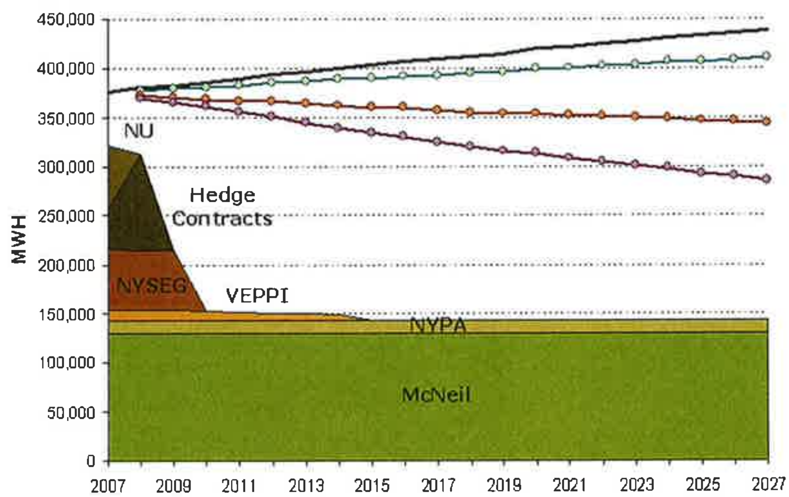
The Resource Analysis in this IRP examined existing resources that are already available, or that are expected to become available during the IRP period (such as Georgia Mountain Community Wind and Hydro Quebec), to meet projected load and to quantify the effects of adding new supply. In developing its supply model for the IRP process, BED used a monthly model of on-peak and off-peak load and supply resources. As in any complex financial model, a host of assumptions were made to perform the analysis. Where possible, BED has used forecasts from publicly available sources such as the Energy Information Administration (EIA).

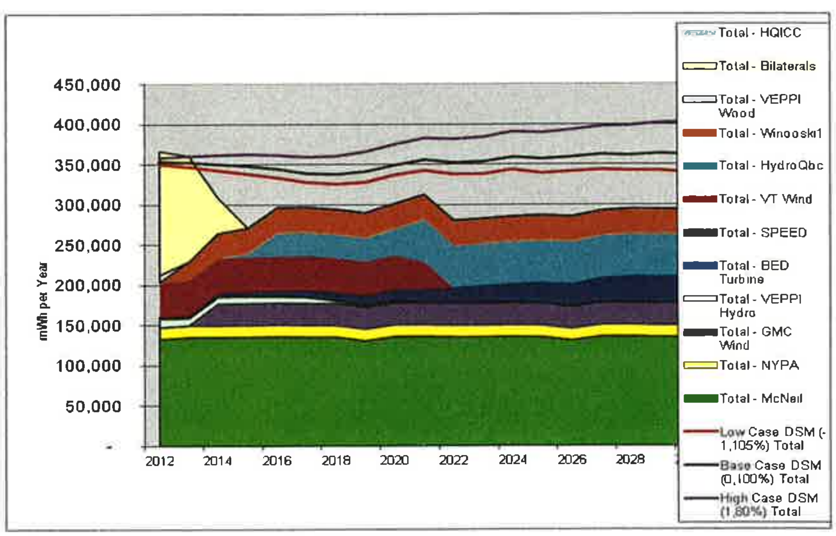
All resource costs are tied directly to contracts where applicable and are run through the model. Both energy and capacity rates have been set to their contractual or historical levels and grown, where applicable, by inflation or by other projections for these values (where use of another method was viewed as more accurate than a simple inflationary escalator).

BED's current power supply portfolio is a combination of long-term contracts, short-term contracts, and generation. Subsequent to the 2008 IRP filing, BED has entered a number of new long term power supply arrangements for renewable resources that have delivered (or will deliver during the period of time covered by this IRP) significant amounts of long term energy at prices more stable than the short term market can offer. Since 2008, BED's strategy has been to maintain diversity in its power supply portfolio while securing long term renewable resources in a cost effective and environmentally conscious manner.

The two graphs below show the projected BED load and the committed resources that are, or will be, available to meet the load. The chart on the upper left (extracted from the 2008 IRP) illustrates the committed resources BED had at the time the 2008 IRP was completed; the chart on the lower right reflects the committed long term resources currently available. In each chart, the three lines at the top represent the high, base, and low projections of BED's load. The bottom areas represent the resources contracted for to meet that load. In the upper left graph, the NU and Hedge Contracts were not from renewable resources, in the lower right graph only the off-white section at the upper left represents short term contracts that are not renewable. As can be seen from these two charts, BED has contracted for significant new long-term resources to meet its customer's needs, all of which are renewable since 2008.

Figure 1-3: Power Supply Portfolio





1.6.1 CURRENT RESOURCES & RISK EXPOSURE

The following table summarizes BED's existing resource mix and important features of each supply source.

Table 1-3: FY 2012 Power Supply Summary

Resource	Description	Fuel	Location	Rating MW	Market Capacity	Expiration
McNeil	Dispatchable Unit	Wood	Essex Node 474	25	26.0	N/A
BED GT	Peaking Unit	Oil	Queen City Node 363	22	19.7	N/A
NYPA	Preference Power	Hydro	Roseton Interface Node 4011	2.6	3.0	Niagara – 2025 St Lawrence – 2017
VEPPI	PURPA Units	Wood/ hydro	Various VT Nodes	4.5	2.5 Winter 2.0 Summer	2012-2020
VT Wind	Intermittent Wind	Wind	VT Node 12530	16	6.8 Winter 4.0 Summer	2021
Solar	Solar Contracts	Solar	Internal to BED System	0.3	0.3	2032
ODR	Capacity value or efficiency	Efficiency	Internal to BED System	3.7	3.7	N/A
BED Demand Response	Customer Load Interruptions	Fossil/Passive DR	Internal to BED System	1.8	1.3 (est)	2012
Market	ISO-NE or bilateral energy	System mix	Various NE Nodes	Seasonal	None	<5 years

In fiscal year 2012, the average unit cost of energy and capacity in BED's power supply portfolio was $77.14/MWH excluding debt service associated with the McNeil plant. BED's power supply comes from a variety of sources and fuel types, and its average counterparty credit rating for market purchases is investment grade or better.

Due to its policy of hedging its energy needs through short term contracts, BED has little exposure to the wholesale price of electricity through 2014 (see Figure 1-5). BED's power supply portfolio is primarily exposed to the price of Renewable Energy Credits (RECs) and wood price as a fuel cost for McNeil. Also significant is any volatility in the price of capacity. Price differences due to congestion costs and losses (both items are features of the standard market design market structure) between locations in New England are also a risk that BED tries to hedge by maintaining a variety of different delivery points and by trying to purchase resources close to its load (or in similar regions). In the long term, natural gas remains a component of BED's risk as BED still has about 20% of its long-term needs that have not been met by long term contracts, and because the price of natural gas effects the price BED will pay for the Hydro Quebec contract.

The increased exposure to REC prices and sales is a direct consequence of BED's pursuit of new renewable resources in the last three years. Steps have been taken to help mitigate this risk.

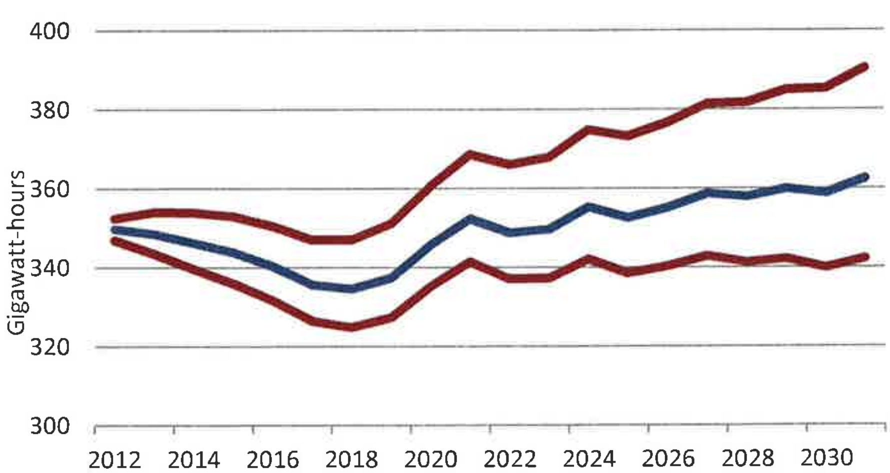
However for reference, when the last IRP was filed, BED received no revenues from the sale of RECs. In FY2012, revenues from REC sales were in excess of $3.5 million, and this value is expected to increase when a full year of REC output is available from the Vermont Wind (2012) and Georgia Mountain Community Wind Project (2013). Revenue from the sale of RECs has been used to reduce the cost associated with purchasing new renewable resources which are at above-market prices.

BED's power supply portfolio has traded a large portion of the short-term flexibility that existed in 2008 (when approximately 60% of BED's load was not covered by long term agreements), for reduced price volatility and renewability in 2012 (where approximately 80% of the load will be met by long-term agreements)(See Figure 1-3). Some flexibility remains in the portion of BED's load for which long-term resources have not been secured. In addition, by having generation that is ready and able to turn on (or operate for more hours) when market prices spike, BED is currently insulated from significant market price volatility.

1.6.2 LOAD PROJECTION FOR RESOURCE PLANNING

Two significant changes were made to the high case, base case, and low case end use load forecasts for use in the power supply model. First, the load forecasts were increased by 1.0 percent to account for high voltage transmission losses on the VELCO system. Second, the projected savings from BED's energy efficiency (DSM) efforts were subtracted from the forecast to account for the benefits of ongoing efforts to use electricity more efficiently in Burlington. The resulting net load forecast curves are used as a primary input into the power supply model. Figure 1-4 shows the high, base, and low forecast loads after adjustments for transmission losses and energy efficiency load reductions.

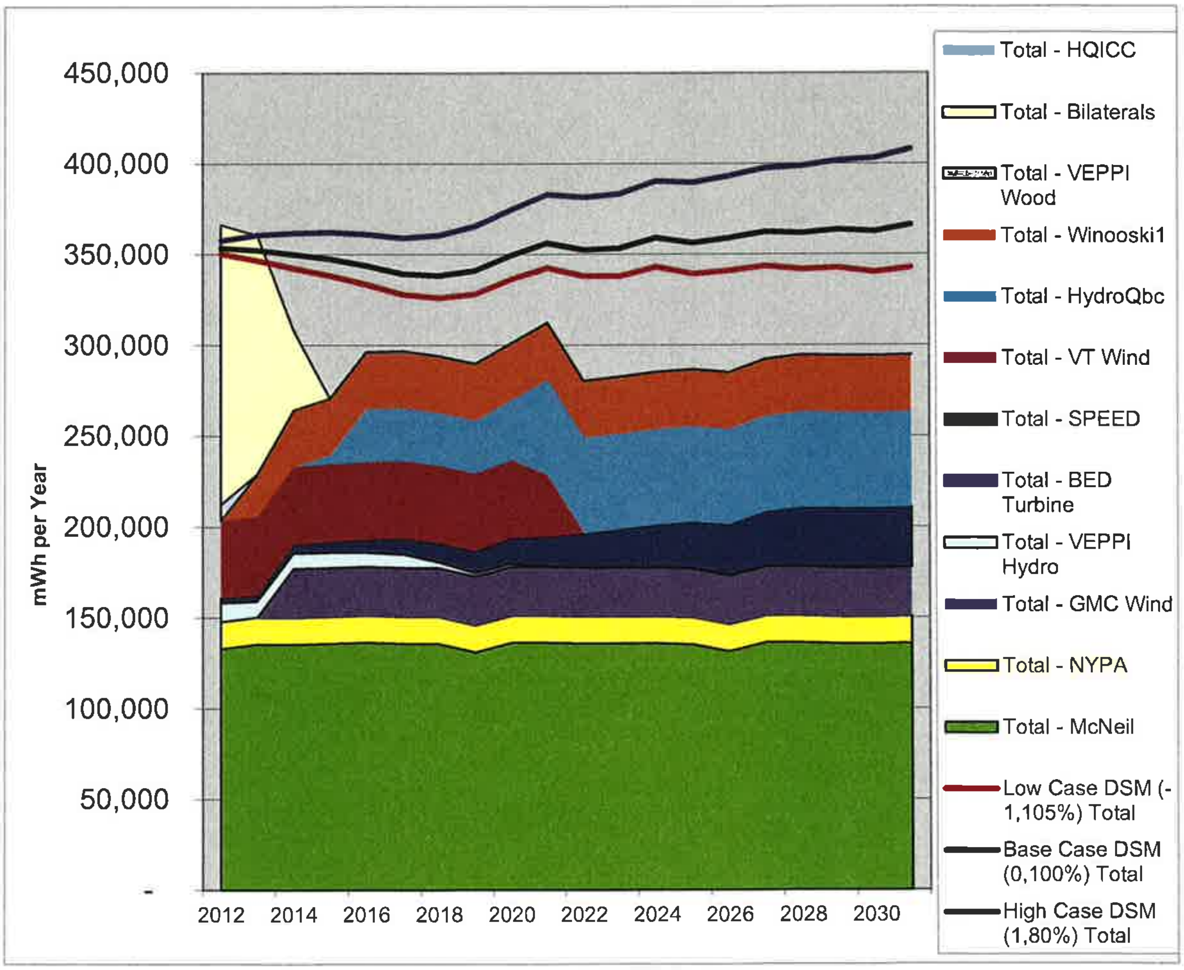
Figure 1-4: BED Wholesale Load Forecasts After Adjustments



1.6.3 ENERGY NEEDS & RESOURCES

BED's long term resource strategy is to hedge its energy needs between its average and its peak load, while managing the spikes and peaks on a short-term basis (such as month to month, seasonally, or through hedging instruments). As supply falls below average loads, BED will acquire new least cost resources that meet its reliability, flexibility, and other criteria that are in line with BED's strategic decision making process. Seasonally, BED will choose to hedge varying levels of its peak load exposure depending on its weather forecast, market view and risk tolerance. BED also follows a planned purchasing policy designed to ensure that BED has minimal exposure to the very short term "spot" markets for electricity. The following figure summarizes BED's existing supply sources and compares expected supply to forecasted energy needs.

Figure 1-5: BED Load vs. Energy Resources



As you can see in Figure 1-5, BED is short of energy supply throughout the next decade though much less so than in 2008. The timeline of major milestones for significant resource changes as follows:

- Short term contracts expiring in the next several years
- Reliance on short-term contracts being reduced in favor of long-term stability priced contracts
- Georgia Mountain Community Wind is projected to begin deliveries in 2013
- Hydro Quebec power commences in 2015, and increases at the time the 10 year Vermont Wind contract is projected to end

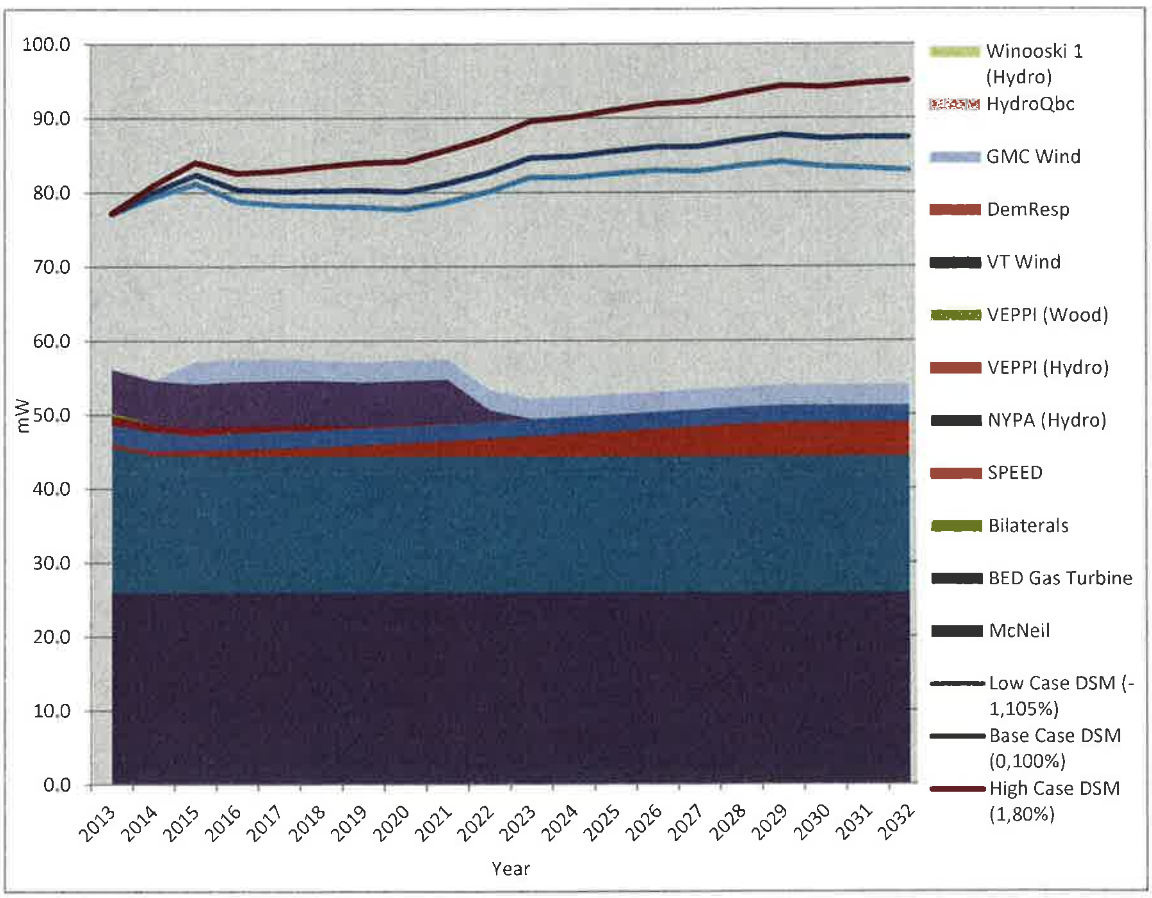
- A heavy reliance on renewable resources to meet long-term needs

1.6.4 CAPACITY NEEDS & RESOURCES

Part of the supply modeling includes estimating BED's capacity requirement with ISO New England. BED's capacity requirement is a function of its load at the time of the ISO-NE annual peak load. The capacity forecast is based on projections of BED's peak load at the time of the New England annual peak, less projected energy efficiency impacts, and further reduced by any in-city Solar and Demand Response savings included in the case.

BED's supply portfolio is forecast to be short on capacity through the planning period in the absence of new capacity contracts or unit entitlements. This is in part a function of some load growth, and in part because renewable resources (such as wind, hydro, etc) are typically not good providers of capacity. BED has explicitly considered this situation in its 2012 IRP to attempt to evaluate the risk posed by this shortfall, and to try to determine if action should be taken to increase the amount of capacity producing resources. The following chart summarizes BED's capacity outlook for the 20-year planning period including resources currently in service or that have been contracted for.

Figure 1-6: BED Capacity Obligation vs. Capacity Resources



1.6.5 DECISION ANALYSIS

The first step in the decision analysis was to form an IRP committee consisting of two members of the Burlington Electric Commission, two representatives of BEDs customers, and BED resource planning staff. This committee began by reviewing the fundamental markets and conditions that comprise BED's business to provide everyone with a level starting point. Next the group considered the "questions" that BED would seek to address in this IRP. BED found that this IRP was interesting in that several key decisions, that might normally have been the subject of this IRP analysis, were dealt with between IRPs for a variety of reasons. First, the level of energy efficiency expenditures, one of the items considered in the prior IRP, was determined outside the IRP process in a series of regulatory hearings and decisions as a result of the Energy Efficiency Utility restructuring process lead by the PSB.

Second, the decision to proceed with the Advanced Metering Infrastructure, and Distribution Automation were subjected to a review similar to an IRP, but the time constraints on the Department of Energy grant application process, coupled with the importance of that grant in making proceeding feasible for BED, resulted in this decision being made in 2011 without waiting for this IRP analysis.

In light of these two major decisions having been made prior to the IRP commencing, and with uncertainty making analysis of several other items premature at this time (electric vehicle impacts and the form that new rates might take following AMI deployment), the decision was made to take the opportunity to revisit several important resource decisions in light of significant market changes following the prior IRP filing. Some modeling of AMI effects were included in the evaluation of the potential for expanded demand response activities. Electric Vehicles ("EVs") are considered as prohibitively expensive for large scale adoption at this time. It is BED's expectation that a more detailed review of EV's and alternate rate impacts will be included as significant components of its next IRP.

In light of BED's previous IRP and actions made pursuant to it, the decisions focused on were:

1. Given the gap between BED's capacity obligation and its capacity producing resources, is investment in some form of capacity producing resource(s) advisable at this time?

2. Due to the apparently long-term decrease in the market price of natural gas and wholesale electricity, should BED continue to acquire new renewable resources to meet its remaining load obligations at this time?

BED created supply scenarios representing options to serve future un-hedged energy and capacity needs. BED recognizes it does not have the need for, or resources to, invest in all the possible supply resources it can pursue. In order to make the analysis manageable, a reasonable set of resource assumptions or plausible investment decisions needed to be identified. Therefore nine plausible supply scenarios were created to reflect how BED would serve load into the future.

Table 1-4: Decision Scenarios

Case	Case ID	Decision Path
1	C1-E1	High DSM, No Capacity Resources, 5 Yr Existing Renewable Energy Contract
2	C1-E2	High DSM, No Capacity Resources, Natural Gas Combined Cycle Energy
3	C1-E3	High DSM, No Capacity Resources, New Renewable Energy (Wind)
4	C2-E1	High DSM, Traditional Peaking Capacity, 5 Yr Existing Renewable Energy Contract
5	C2-E2	High DSM, Traditional Peaking Capacity, Natural Gas Combined Cycle Energy
6	C2-E3	High DSM, Traditional Peaking Capacity, New Renewable Energy (Wind)
7	C3-E1	High DSM, 5 MW Solar, Max DR, Some Traditional Peaking, 5 Yr Existing Renewable Energy Contract
8	C3-E2	High DSM, 5 MW Solar, Max DR, Some Traditional Peaking, Natural Gas Combined Cycle Energy
9	C3-E3	High DSM, 5 MW Solar, Max DR, Some Traditional Peaking, New Renewable Energy (Wind)

BED's IRP committee developed the above nine scenarios. These scenarios, when coupled with the possible changes to the four significant variables selected by the Committee, resulted in calculation of 729 results (the same number as in the prior IRP and nearing the limit of manageability with the tools available to BED).

Nineteen potentially significant variables were initially considered in the sensitivity analysis to determine which variables would be most important to the decision analysis. These variables were generally either price related (such as natural gas price projections and oil price projections) or were volume related (such as energy production capability at McNeil or loads). Table 1-5 shows the unit inputs and volatility ranges for each variable that was modeled and identifies them as P (Price) or V (Volume).

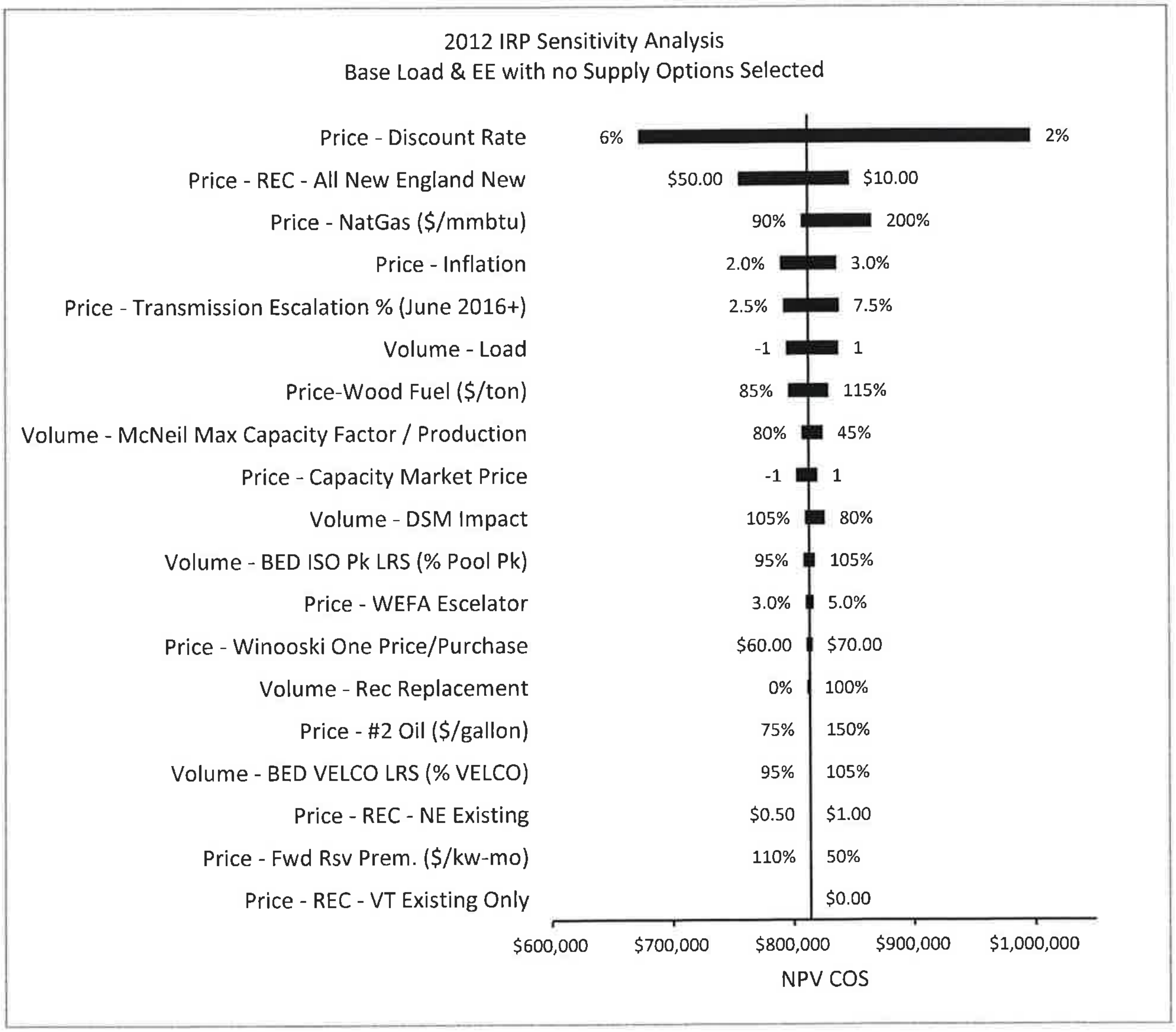
Table 1-5: Unit Inputs and Variable Volatility for SenSit Analysis (Nominal 1st Year Values)

	Variable	Description	Unit	Low	Base	High	Low % Δ	High % Δ
1	P-NatGas	Price - NatGas ($/mmbtu)	% Base	90%	100%	200%	-10%	100%
2	P-VTExistREC	Price - REC - VT Existing Only	$/REC	$0.00	$0.00	$0.00	N/A	N/A
3	P-NEExistREC	Price - REC - NE Existing	$/REC	$0.50	$0.75	$1.00	-33%	33%
4	P-NENewREC	Price - REC - All New England New	$/REC	$10.00	$25.00	$50.00	-60%	100%
5	V-RecRep	Volume - Rec Replacement	% Base	0%	100%	100%	-100%	0%
6	P-Capacity	Price - Capacity Market Price	Numeral	-1	0	1	N/A	N/A
7	P-Wood	Price-Wood Fuel ($/ton)	% Base	85%	100%	115%	-15%	15%
8	P-Oil	Price - #2 Oil ($/gallon)	% Base	75%	100%	150%	-25%	50%
9	P-FRM	Price - Fwd Rsv Prem. ($/kW-mo)	% Base	50%	100%	110%	-50%	10%
10	P-WinOne	Price - Winooski One Price/Purchase	$/MWh	$60.00	$65.00	$70.00	-8%	8%
11	P-WEFA	Price - WEFA Escalator	%	3.0%	4.0%	5.0%	-25%	25%
12	P-Inflation	Price - Inflation	%	2.0%	2.5%	3.0%	-20%	20%
13	P-TransEsc	Price - Transmission Escalation % (June 2016+)	%	2.5%	5.0%	7.5%	-50%	50%
14	P-Discount	Price - Discount Rate	%	2%	4%	6%	-50%	50%
15	V-McNCF	Volume - McNeil Max Capacity Factor / Production	%	45%	60%	80%	-25%	33%
16	V-Load	Volume - Load	Numeral	-1	0	1	N/A	N/A
17	V-DSM	Volume - DSM Impact	$	80%	100%	105%	-20%	5%
18	V-VELCOLRS	Volume - BED VELCO LRS (% VELCO)	% Base	95%	100%	105%	-5%	5%
19	V-ISOLRS	Volume - BED ISO Pk LRS (% Pool Pk)	%	95%	100%	105%	-5%	5%

*Shaded values represent key variables

Tornado diagrams serve to graphically display how sensitive the analysis is to changes in each of the variables. The larger the black rectangle the more sensitive the outcome is to this variable. The size of the rectangle represents the "Swing" or change in the cost of service that results from changing that variable from its low value to its high value. The major variables are the factors that will cause BED's decisions to be a financial success or failure. The Tornado diagram below (Figure 1-7) represents the variable sensitivities for BED's portfolio prior to including any of the proposed resource options under consideration.

Figure 1-7: Tornado Diagram – No Additional Resources



In addition to the simple tornado analysis included above, and used in the prior IRP, BED reviewed the change in significance in variables between scenarios (i.e. the change in the "Swing" for a variable between cases). The theory was that a variable might be significant in the tornado charts for all scenarios, but that it could also result in an equally wide "Swing" in all of those scenarios (or differ little between scenarios). If so, selecting a variable with less overall significance, but more change in significance between different scenarios, would be more informative.

As a result of the sensitivity analysis of both the tornado charts and the changes in tornado charts across scenarios, BED choose the P-Discount, P-NENewREC (combining CT1 and All New England New REC prices into a single variable), P-NatGas, P-Capacity, and as the significant variables for this decision analysis, since they were the significant variables on the tornado diagrams through each of the nine of decision scenarios and were the variables with the greatest change from scenario-to-scenario and thus assumptions about these variables by the committee members would be more likely to change the desired scenario selection.

The next step was to combine all possible combinations of the nine scenarios and the four key variables in a decision tree analysis, and to assign probabilities to each of the branches. The decision tree is made up of 9 major branches with 81 unique probabilities for each branch (based on the values assumed for each key variable) tied to each branch. Figure 1-8 gives a graphic illustration of the Decision Tree for the 2012 IRP.

Figure 1-8: 2012 – BED IRP Decision Tree

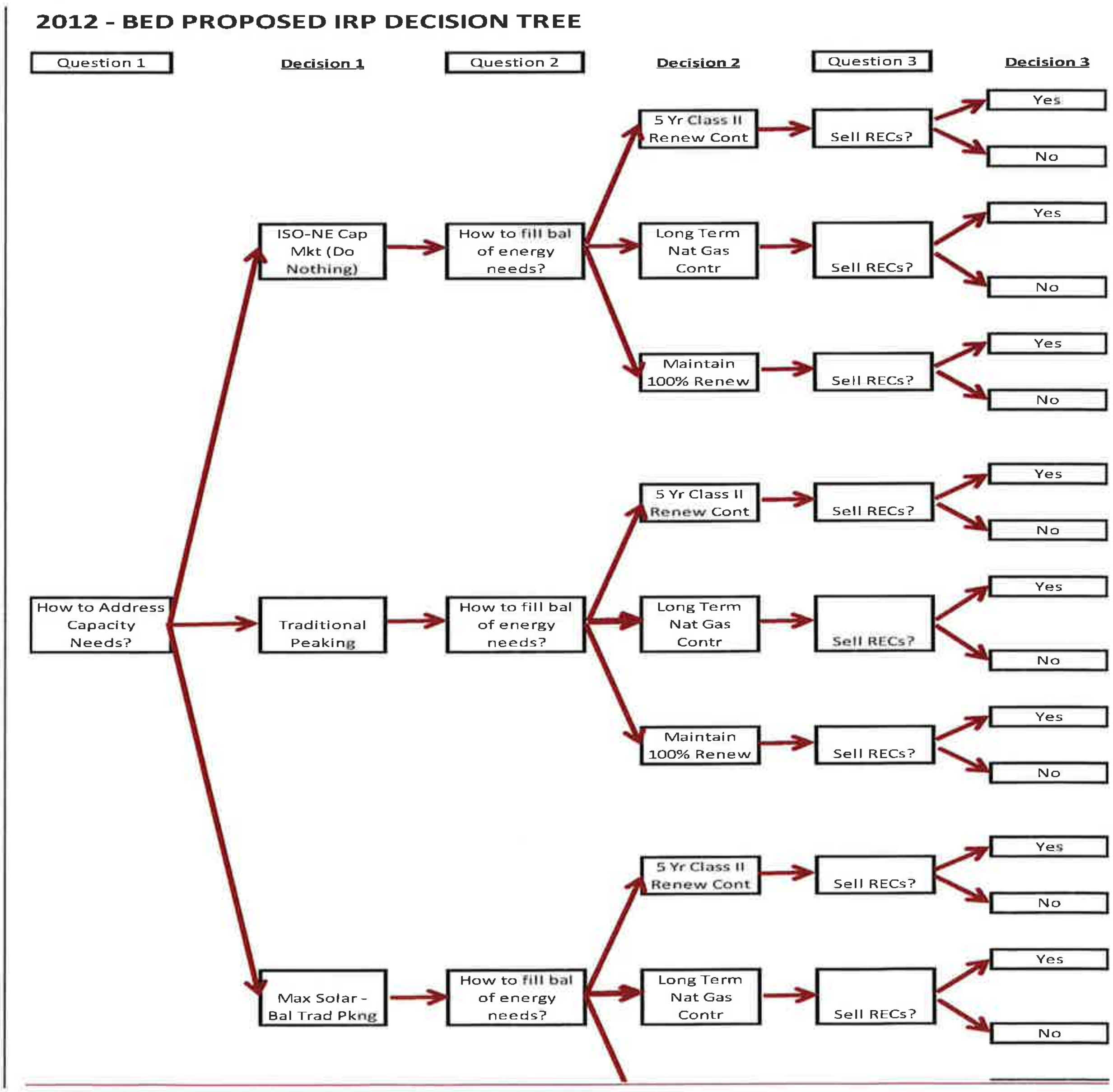
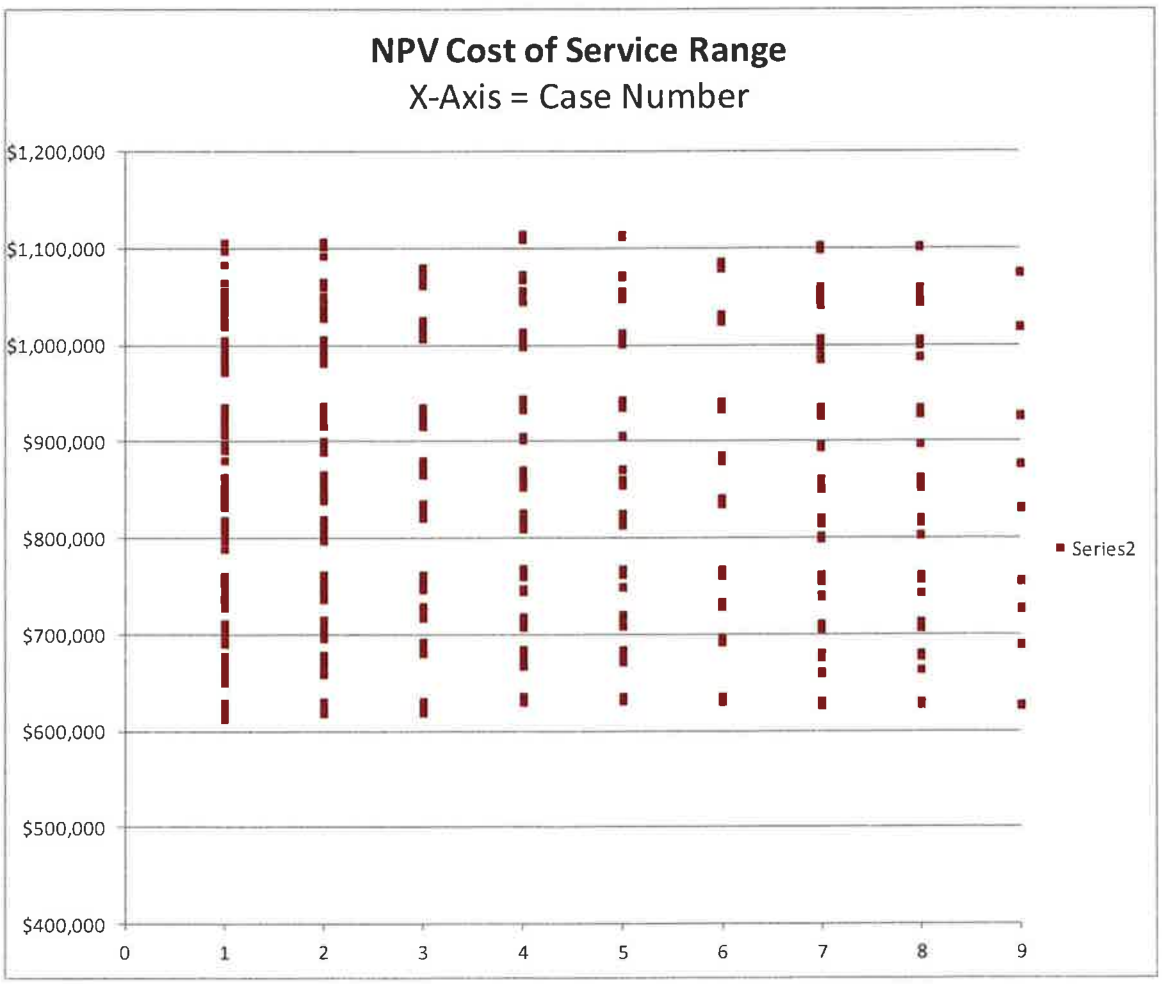


Table 1-6: Tabular Decision Tree, 9 Scenarios, 81 Individual Cases per Secnario

Case	Case ID	Decision Path
1	C1-E1	High DSM, No Capacity Resources, 5 Yr Existing Renewable Energy Contract
2	C1-E2	High DSM, No Capacity Resources, Natural Gas Combined Cycle Energy
3	C1-E3	High DSM, No Capacity Resources, New Renewable Energy (Wind)
4	C2-E1	High DSM, Traditional Peaking Capacity, 5 Yr Existing Renewable Energy Contract
5	C2-E2	High DSM, Traditional Peaking Capacity, Natural Gas Combined Cycle Energy
6	C2-E3	High DSM, Traditional Peaking Capacity, New Renewable Energy (Wind)
7	C3-E1	High DSM, 5 MW Solar, Max DR, Some Traditional Peaking, 5 Yr Existing Renewable Energy Contract
8	C3-E2	High DSM, 5 MW Solar, Max DR, Some Traditional Peaking, Natural Gas Combined Cycle Energy
9	C3-E3	High DSM, 5 MW Solar, Max DR, Some Traditional Peaking, New Renewable Energy (Wind)

Calculating and plotting the Present Value of BED's cost of service for each scenario, and each of the 81 possible variable settings for each scenario, yields the 729 points in the following "scatter plot" graph (Figure 1-9). Each "column" of red dots represents one of the scenarios, and shows the range of possible present value of cost-of-service that can result under that scenario from each of the possible settings of the key variables. Figure 1-9 simply shows the range of results, it does not show how likely any individual outcome might be,.

Figure 1-9: Scatter Plot of Decision Tree Results - Optimal Path



If compared to the prior IRP, one thing becomes immediately apparent. The difference in results between scenarios has decreased both due to changes in the assumptions regarding underlying variables, and the fact that BED is now looking at the results from meeting roughly 20% of its need (versus the 60% considered in the prior IRP). The overall range however is not materially different from the prior IRP, showing possible results of approximately $600 million to $1,100 million NPV cost-of-service over 20 years. The highest cost outcomes of the 9 supply scenarios occur due to combinations of high gas, capacity, and low REC prices. The lowest cost scenarios occur primarily due to base or low gas prices and high REC prices. Notice that Scenario 1, Market Capacity plus 5 year existing renewable energy contract, resulted in the lowest range of costs of the initial nine scenarios reviewed.

The next step was to have BED's decision makers assign their own probabilities to each of the key variables to allow staff to calculate the present value of cost-of-service for each scenario for that decision maker. The probability assignments for each of the key variables are largely subjective. A combination of market view and professional judgment are the prime inputs to assigning probabilities to each price range. The following table summarizes the probabilities assigned to the key variable ranges by BED staff and policy makers.

Table 1-7: Decision Tree Probabilities

Respondent	Case	P-Discount Rate	P-REC	P-Gas	P-Capacity
Staff #1	High	50%	10%	30%	30%
	Base	25%	60%	60%	60%
	Low	25%	30%	10%	10%
Staff #2	High	20%	25%	20%	10%
	Base	30%	65%	70%	60%
	Low	50%	10%	10%	30%
Staff #3	High	25%	30%	45%	5%
	Base	65%	55%	50%	15%
	Low	10%	15%	5%	80%
Committee #1	High	30%	50%	10%	50%
	Base	40%	40%	30%	50%
	Low	30%	10%	60%	0%
Committee #2	High	5%	10%	10%	15%
	Base	20%	75%	10%	50%
	Low	75%	15%	80%	35%
Commissioner #1	High	20%	25%	10%	20%
	Base	40%	50%	40%	50%
	Low	40%	25%	50%	30%
Commissioner #2	High	0%	10%	10%	20%
	Base	30%	80%	80%	70%
	Low	70%	10%	10%	10%
Commissioner #3	High	10%	20%	5%	33%
	Base	80%	50%	50%	34%
	Low	10%	30%	45%	33%

1.6.6 OPTIMAL PATH

Several conclusions were drawn initially from the results of the first nine scenarios. The apparent least cost path was a combination of mid-term contracts for existing renewable resources and the acquisition of Winooski One (which was assumed in all scenarios) – coupled with taking no action to acquire long-term capacity resources (either traditional peaking generation or a blend of peaking generation and more renewable options such as solar and demand response). Only one evaluator assigned probabilities to the significant variables that were different enough to yield a different answer. One other change to this IRP was to maintain a result for the "Average Evaluator" which reflected a non-weighted averaging of the probabilities assigned by all evaluators.

Table 1-8: Scenario Expected Value NPVs ($1,000s)

SECTION 1									
WITH REC SALES & REPURCHASES- Probability Weighted Cost of Service (NPV, 1,000s)									
Respondant/Case	C1-E1	C1-E2	C1-E3	C2-E1	C2-E2	C2-E3	C3-E1	C3-E2	C3-E3
Staff- 1	$ 808,356	$ 812,012	$ 813,328	$ 820,519	$ 821,128	$ 821,582	$ 814,883	$ 815,497	$ 815,950
Staff - 2	$ 873,536	$ 878,442	$ 879,667	$ 889,722	$ 890,569	$ 890,649	$ 883,358	$ 884,210	$ 884,292
Staff - 3	$ 797,367	$ 804,367	$ 795,674	$ 815,996	$ 818,322	$ 808,313	$ 809,575	$ 811,904	$ 801,896
Committee - 1	$ 807,272	$ 809,695	$ 812,451	$ 817,927	$ 817,682	$ 819,682	$ 812,115	$ 811,878	$ 813,877
Committee - 2	$ 942,951	$ 948,046	$ 961,200	$ 960,351	$ 961,073	$ 973,008	$ 954,537	$ 955,268	$ 967,197
Commission - 1	$ 854,596	$ 859,021	$ 867,927	$ 869,836	$ 870,434	$ 878,271	$ 864,466	$ 865,071	$ 872,903
Commission - 2	$ 946,171	$ 950,011	$ 958,734	$ 960,914	$ 961,062	$ 968,736	$ 954,509	$ 954,661	$ 962,341
Commission - 3	$ 816,583	$ 820,591	$ 832,186	$ 830,613	$ 831,100	$ 841,713	$ 825,946	$ 826,438	$ 837,046
AVERAGE EVALUATOR	$ 856,058	$ 860,456	$ 865,021	$ 870,963	$ 871,623	$ 875,136	$ 865,122	$ 865,788	$ 869,301

The IRP committee was surprised by the conclusion that the market capacity scenario (C1-E1) was better than the "5 MW solar, maximize Demand Response, and only use traditional peaking for the remainder" scenario (C3-E1). Additional research into the three capacity technologies included in this scenario resulted in a clearer picture of what was occurring in the analysis. Solar, on its own, appears to reduce costs. Demand Response prices changed as target levels were increased in order to attract new participants. Therefore, Demand Response reduced costs at its current level of effort and prices, approximately broke even at the first step of expansion (1.8 to 3.3 MW), and actually increased costs at very high levels of effort (5 MW). This led to the creation of two additional "hybrid" scenarios to determine if the results of the initial nine scenarios could be bettered. The two new scenarios were:

Table 1-9: Additional Decision Scenarios

Case	Case ID	Decision Path
10	C4-E4	High DSM, 5 MW Solar, Mid DR, Market for Remaining Pk Needs, New Renewable Energy (Wind)
11	C5-E5	High DSM, 5 MW Solar, Existing DR, Market for Remaining Peak Needs, 5 Yr Existing Renewable Energy Contract

The charts below add the two new scenarios to both the scatter chart (Figure 1-10) and the expected value table (Table 1-10). As can be seen, one of the new scenarios (C5-E5 "5 MW in-city Solar, Existing Demand Response, 5 year Existing Renewable Energy contract) resulted in an improved NPV Cost of Service for almost all of the evaluators.

Figure 1-10: NPV Cost of Service Range

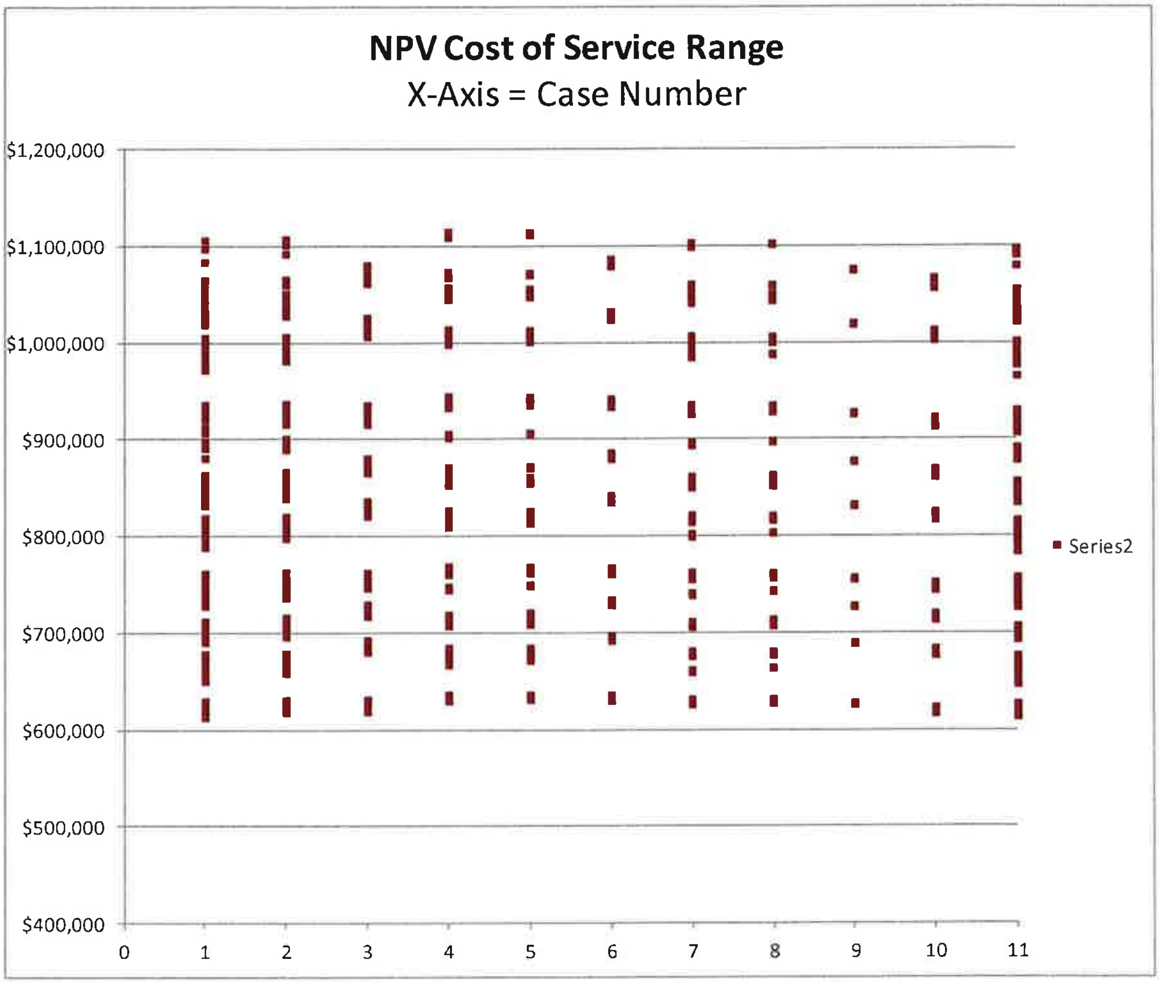


Table 1-10: Cost of Service with REC Sales and Repurchases

SECTION 1			
WITH REC SALES & REPURCHASES- Probability Weighted Cost of Service (NPV, 1,000s)			
Respondant/Case	C1-E1	C4-E4	C5-E5
Staff- 1	$ 808,356	$ 806,814	$ 806,090
Staff - 2	$ 873,536	$ 874,625	$ 871,587
Staff - 3	$ 797,367	$ 790,527	$ 795,822
Committee - 1	$ 807,272	$ 807,455	$ 804,512
Committee - 2	$ 942,951	$ 957,194	$ 941,904
Commission - 1	$ 854,596	$ 863,907	$ 853,377
Commission - 2	$ 946,171	$ 953,104	$ 943,934
Commission - 3	$ 816,583	$ 828,503	$ 815,722
AVERAGE EVALUATOR	$ 856,058	$ 860,118	$ 854,299

1.7 Conclusions and Action Plan

This Integrated Resource Plan has identified a variety of efforts that BED will undertake to continue providing reliable, economical, and environmentally friendly electricity to its consumer owners.

The "biggest bang for the buck" is achieved by making smart, informed resource decisions. In undertaking this IRP, BED has completed a rigorous process that utilized both the scenario analysis preferred by the PSB in framing plausible supply scenarios and the Decision Analysis preferred by the DPS. Both approaches yielded valuable insight into the impacts of BED's future resource decisions.

In all scenarios, this IRP takes into account the pre-existing commitment to enhanced efficiency spending and to improving the distribution and metering system through the projects funded by the DOE grant process, as well as the resource commitments entered into subsequent to the 2008 IRP as well as the acquisition of the output from Winooski One. In light of the significant drop in Natural Gas prices, and the continued low capacity market prices, this IRP supports proceeding cautiously in entering additional long-term high-priced contracts at this point with one exception. The additional scenarios run support long-term investment in solar generation within the City of Burlington as a means of economically controlling capacity and transmission costs. Coupled with acquiring the Winooski One hydro facility located in Burlington, entering a mid-term (five year) contract for the output of existing renewable resources, and maintaining existing levels of demand response capability, this course of action not only results in the least cost result, but will preserve flexibility to react to possible changes in Vermont Statutes relating to renewable portfolio standards and the assignment of state mandated resources to BED. Nevertheless, BED continues to believe that the creation of new renewable energy-producing resources has great merit and will continue to seek such resources if their costs prove to be lower than was assumed in this IRP for such resources, other benefits of such resources are identified, or market conditions change sufficient to warrant revisiting this conclusion.

The specific Action Plan, which includes the items discussed above as well as some other activities desirable in the next three years, is:

1. **Continue BED's energy efficiency activities based on the recently PSB approved budget levels and appropriate avoided costs**
    a. Continue to develop an on-the-bill financing tool for electric efficiency measures to encourage participation
    b. Continue to develop a PACE financing program for all fuel energy efficiency and renewable energy measures to encourage participation

2. **Proceed with purchase of Winooski One hydro facility**
    a. Communicate intent to exercise option to Winooski One Partners
    b. Retain expert services in resource valuation and engineering due diligence
    c. Verify cost-effectiveness of any final purchase price using 2012 IRP model processes
    d. Identify most advantageous financing structure and close transaction if economically positive

3. **Increase the level of behind-the-utility-meter solar generation in Burlington**
    a. Conduct an RFP for Solar on Public Buildings
    b. Continue BED Solar Rider – Research TOU,LG,PS Implications of Act 125
    c. Continue entering Purchase Power Agreements for viable projects
    d. Confirm IRP assumptions regarding installed/long-term cost of solar

4. **Maintain BED's existing demand response capability**
    a. Consider expansion of DR capability if this can be done at current rates and from passive load reduction (i.e. no additional backup generation)

5. **Purchase 5 year existing renewable contract**
    a. Execute a contract for 5 years output from existing renewable resource
    b. Consider converting 5 year contract to a rolling five year contract by adding a one year extension annually
    c. During the duration of this agreement (either 5 year or 5 year rolling) monitor energy market conditions for changes in key variables

6. **Continue seeking additional long-term renewable resources to fill remaining supply gap without substantial rate impacts**

7. **Renewability**
    a. When economical, purchase Class II RECs to replace high value RECs sold and be able to demonstrate renewability and increase market pressure for new renewable creation

8. **REC sales**
    a. Continue the existing REC sales hedging program to manage rate impacts from renewable resources
    b. Expand the hedging program to include sale of long term 3-5 year REC strips when prices are advantageous to lock in beneficial outcomes identified in the IRP and minimize the risks identified
    c. Monitor REC markets closely and maintain efforts to preserve value for McNeil, wind, and solar RECs

9. **Other actions**
    a. Monitor legislative activity, particularly as it relates to Renewable Portfolio Standards and allocation of Standard Offer resources to BED
    b. Leverage the new AMI infrastructure to control peak loads and related costs
    c. Gather the data to incorporate electric vehicle impacts and potentials as well as smart meter advances in more detail in BED's next IRP

BED's IRP is intended to act as a plan for meeting the needs of Burlington consumers' energy needs into the future, but it does not actually commit BED to any specific action unless all required approvals for that action are first obtained through normal City processes. In addition, BED must continually update data and re-evaluate its supply alternatives as well as the assumptions relating to the variables that led to these preliminary conclusions. The results of this document tell BED what areas it needs to do more work on and what critical paths are necessary to reach a least cost outcome. As stated by the Public Service Board "The IRP planning process is properly viewed as dynamic rather than static; conditions change and planning projections ought to be updated as necessary to reflect important developments."[1] BED's IRP is just that; a plan that will require continual revaluation and further analysis of investment decision paths.

(1) Docket 6018, Order of 4/17/98 at 14

Resolution Relating to

APPROVAL OF BURLINGTON ELECTRIC DEPARTMENT'S 2012 INTEGRATED RESOURCE PLAN

RESOLUTION ________

Sponsor(s): Councilors Shannon, Decelles, Paul, Bushor: Bd. of Finance

Introduced: ________

Referred to: ________

____

Action: ________

Date: ________

Signed by Mayor: ________

CITY OF BURLINGTON

In the year Two Thousand Twelve...

Resolved by the City Council of the City of Burlington, as follows:

That, WHEREAS, Section 218c of Title 30, Vermont Statutes Annotated, requires all Vermont electric utilities, including Burlington Electric Department ("BED"), to prepare and implement a least-cost integrated plan for the provision of energy services; and

WHEREAS, BED has prepared its 2012 Integrated Resource Plan ("Plan"), a copy of which is available in the Offices of the Chief Administrative Officer, which is BED's plan for meeting Burlington's need for electric services, after safety concerns are addressed, at the lowest present value life cycle cost, through a strategy of combining investments in energy supply and energy efficiency;

WHEREAS, the development of BED's 2012 Integrated Resource Plan was advised by a public committee established by the Board of Electric Commissioners;

WHEREAS, BED continues to attempt to discuss its Integrated Resource Plan with all of the City's seven Neighborhood Planning Assemblies, and has received feedback from two of those Neighborhood Planning Assemblies;

WHEREAS, at a special meeting on July 26, 2012, the Board of Electric Commissioners approved BED's 2012 Integrated Resource Plan's approach and preferred solution;

WHEREAS, BED is obligated to file its 2012 Integrated Resource Plan with the Vermont Public Service Board on or before September 30, 2012;

Resolution Relating to

APPROVAL OF BURLINGTON ELECTRIC DEPARTMENT'S 2012 INTEGRATED RESOURCE PLAN

NOW, THEREFORE, BE IT RESOLVED by the City Council that BED's 2012 Integrated Resource Plan be and hereby is approved; and

BE IT FURTHER RESOLVED that BED is hereby authorized to file its Plan with the Public Service Board and take all steps necessary to obtain approval of the Plan.

211150-82