# WASHINGTON ELECTRIC COOPERATIVE, INC.

# 2017 INTEGRATED RESOURCE PLAN
# 2017 – 2036

**Submitted by**
**Washington Electric Cooperative, Inc.**

**July 2017**

# Table of Contents

## List of Acronyms

ACP – Alternative Compliance Payment
AMI – Automated Metering Infrastructure
ARRA – American Recovery and Reinvestment Act
CAA – Clean Air Act
CAGR – Compound Annual Growth Rate
CCHP – Cold Climate Heat Pump
CEP – Comprehensive Energy Plan
CWP – Construction Work Plan
DPS – Department of Public Service
DSM – Demand Side Management
DUP – Distributed Utility Planning
EEU – Energy Efficiency Utility
EPA – Environmental Protection Act
EVT – Efficiency Vermont
EV – Electric Vehicles
FCA – Forward Capacity Auction
FCM – Forward Capacity Market
FERC – Federal Energy Regulatory Commission
HQ B – Hydro Quebec Schedule B
HQUS PPA – Hydro Quebec US Purchase Power Agreement
HQ VJO – Hydro Quebec Vermont Joint Owner
ICAP – Installed Capacity
IRP – Integrated Resource Plan
ISO-NE – Independent System Operators of New England
LFG – Landfill Gas
LMP – Locational Marginal Prices
LNG – Liquid Natural Gas
LSE – Load Serving Entity
NEMA – Northeast Massachusetts
NEPOOL GIS – New England Power Pool Generation Information System
NEWSVT – New England Waste Services of Vermont Landfill

NPV – Net Present Value
NSPC – New Source Performance Standards
NYPA – New York Port Authority
PSB – Public Service Board
PV – Present Value
REC – Renewable Energy Credits
RGGI – Regional Greenhouse Gas Initiative
RNS – Regional Network Service
RPS – Renewable Portfolio Standard
RUS – Rural Utility Service
RTLO – Real-Time Load Obligation
SCADA – Supervisory Control and Data Acquisition
SPEED – Sustainably Priced Energy Enterprise Development Program
TOU – Time of Use
T & D – Transmission and Distribution
UCAP – Unforced Capacity
VEC – Vermont Electric Cooperative
VELCO – Vermont Electric Power Company
VEPPI – Vermont Electric Power Producers Inc.
VPPSA –Vermont Public Power Supply Authority
VSA – Vermont Statutes Annotated
VSPC – Vermont State Planning Committee
WEC –Washington Electric Cooperative

# Executive Summary

As required by 30 V.S.A. § 218c, Washington Electric Cooperative (WEC) has prepared its 2017 Integrated Resource Plan (IRP) for submission to the Vermont Public Service Board (PSB) and the Department of Public Service (DPS or Department). In addition to its regulatory requirements, WEC views the IRP as a valuable planning tool and guiding document. The IRP enables WEC to communicate to various stakeholder groups regarding its plans for power supply, Demand Side Management (DSM), and Transmission and Distribution (T&D) system planning.

As part of WEC's mission, it is committed to meeting the following responsibilities, and each is considered in and addressed by the IRP:

- Provide energy to members as inexpensively as possible;
- Educate and advise its members about using energy safely, wisely, and economically;
- Keep its member-owners informed about their Co-op and its business, economic, regulatory, political, and social environments;
- Minimize the environmental impacts of electric generation and operations;
- Support and promote our local economy and community organizations; and
- Provide leadership and take proactive positions on energy and environmental issues.

The intent of the IRP resource modeling process is to provide important information about the costs, features, and risks of various power supply portfolios that WEC could use in the future to meet its system load requirements. The goal is to project cost and cost variance, emissions profiles, and other qualities associated with each portfolio, under a broad range of future loads, market prices, economic conditions, and other factors affecting performance, such as market or regulatory changes.

WEC's 2017 IRP filing is not analyzing the need to replace or enter new long-term power commitments. In WEC's 2014 IRP, it completed a rigorous resource analysis in which it analyzed various portfolios and stress tested the assumptions used to calculate costs. Given that little has changed since the 2014 filing, completing the same analysis in 2017 was determined to yield little new information and results.

As noted in the Department's IRP guidelines, "utilities should use the IRP process to address questions that are the most relevant to the utility at the time of the IRP." [1] Since little will change in WEC's resource outlook in the next several years, it is focusing less on new power supply commitments and more on other key issues important to WEC (modernizing grid, distributed generation, consumer expectations, and controlling costs). WEC provides a summary of the 2014 power supply analysis and results for context in its 2017 IRP as this work remains relevant today. The impacts of the analysis and key variables remain important to WEC today and the Co-op provides a high level summary in this filing of the work completed in 2014.

The planning period for the IRP is January 1, 2017 – December 31, 2036. To follow is a brief summary of WEC's IRP. WEC begins by describing its outlook of its existing resources and future load. WEC also includes an assessment of its resource mix and key drivers to WEC costs from variations in the sources of power. WEC provides a summary of its power supply resources and projected requirements as well as its plans for various legislative and regulatory mandates. The report also provides a detailed review of WEC's transmission and distribution (T&D) systems with a scoping analysis mapped out to assess future distributed generation penetration.

As noted in the 2016 Comprehensive Energy Plan, utilities should use the IRP process to address questions that are the most relevant to the utility at the time of the IRP. WEC met with the Department in advance of the filing to discuss its key issues and questions it desired to address in this filing. WEC and the Department agreed that since WEC is not making large or longer term power supply decisions for the next five years, its IRP will focus on key issues identified by WEC rather than new power cost simulation and modeling efforts.

As a result WEC's IRP is structured to focus on the following areas which WEC believes are key issues:

- Revisit key power cost drivers from 2014 IRP analysis and reaffirm relevance of each driver to WEC's current situation and costs;
- Assess ways to control costs and pressures of increasing rates in light of flat to declining load;
- Review FERC relicensing effort of Wrightsville hydro station;
- Provide an overview of important regulatory issues;
    - Act 56 Renewable Energy Standard

[1] 2016 CEP, Appendix B; Guidance for Integrated Resource Plans and 202(f) Determination Requests, page 5

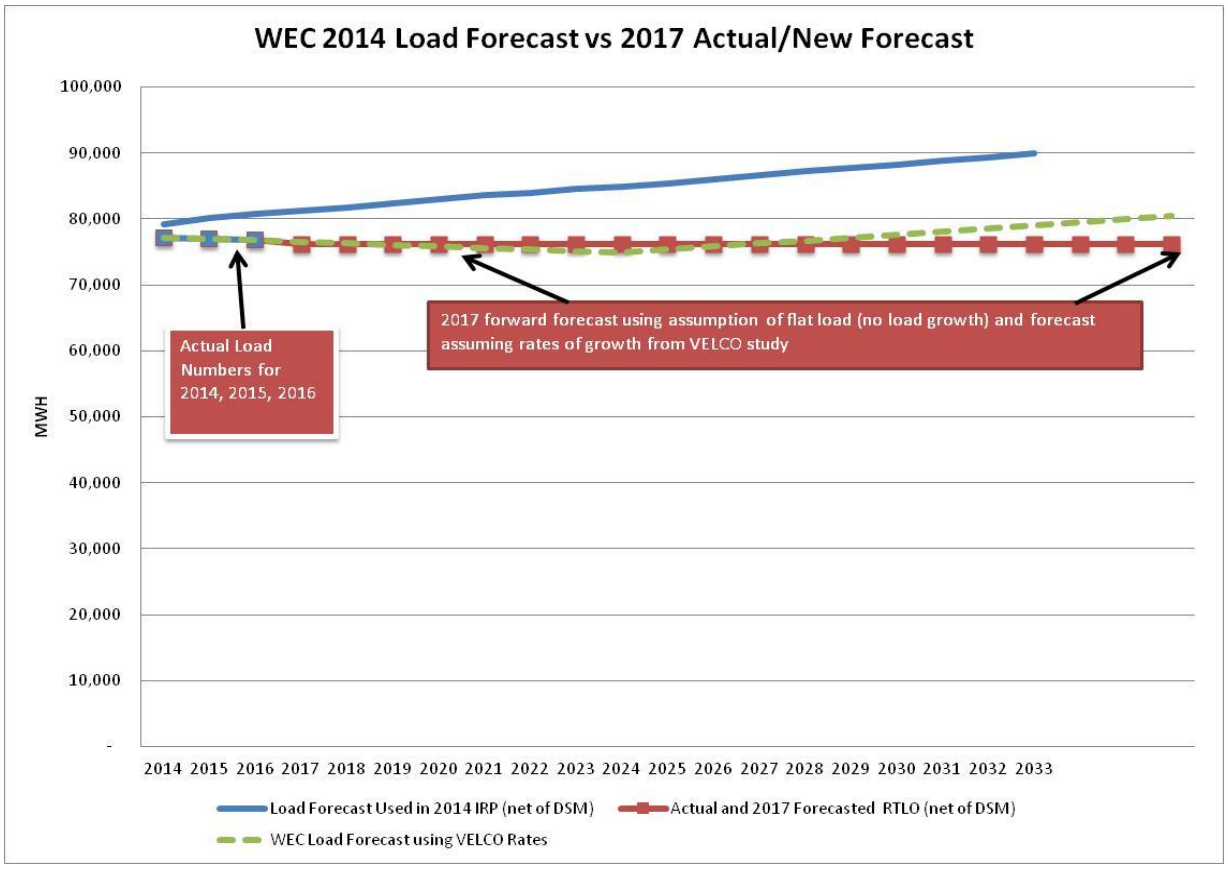
- Act 99 Net Metering
- 2016 Comprehensive Energy Plan

- Assess impacts of distributed generation on the T&D systems.

## Load Forecast

The IRP evaluates costs and other features of WEC's portfolios by modeling system energy requirements *after* adjusting the load forecast for the effects of energy efficiency and other programs already in place and likely to be implemented over the forecast horizon.

Figure ES-1. Load Forecast



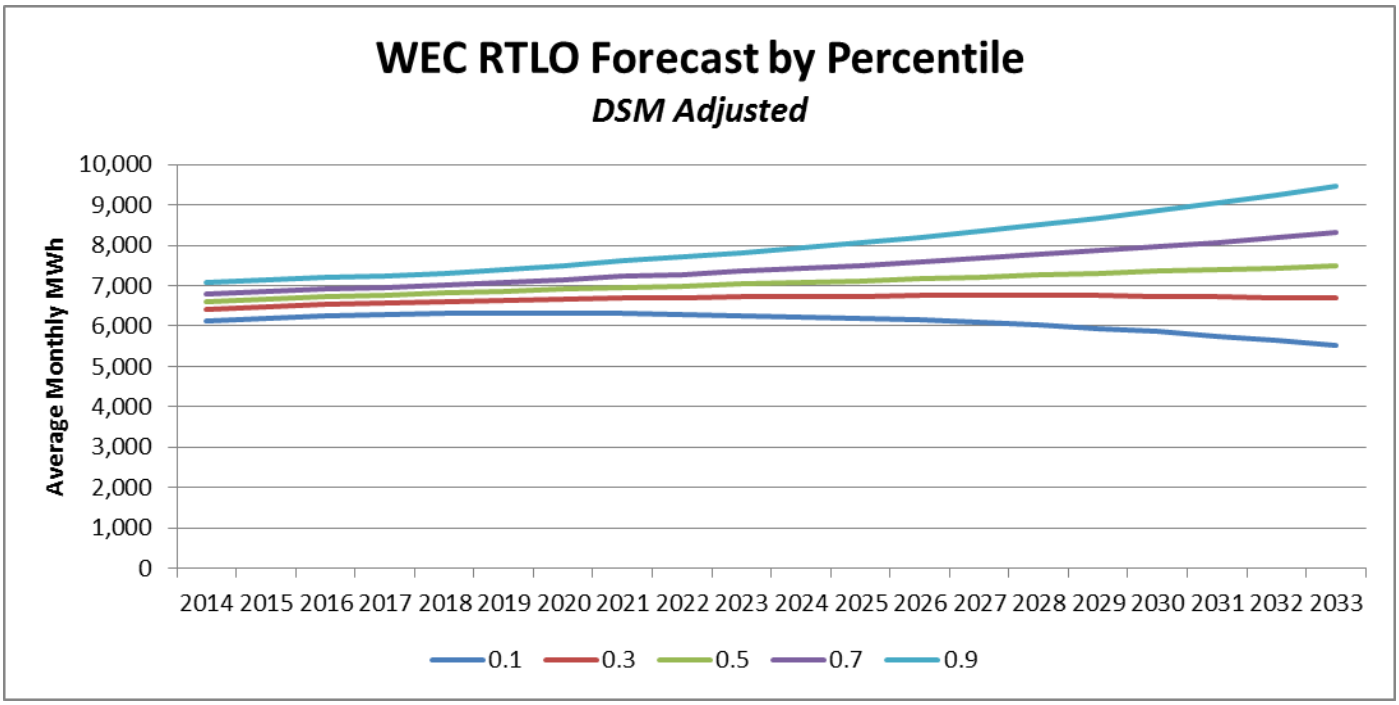

WEC used a projection of flat growth in its outlook for the upcoming 20 years as well as load forecast results from a rigorous state effort developed by VELCO (the results of the state load effort are reported in the 2016 Comprehensive Energy Plan).

A more detailed monthly load forecast is modeled in the IRP portfolio evaluation using software that implements simulation analysis. This tool allows WEC to test a wide range of

potential loads and associated costs, cost variance, and emissions impacts from simulating a wide number of possible future load levels rather than using a single forecast trajectory of load.

Some of the load uncertainty that WEC must consider includes changes in consumption per consumer, number of WEC members, the effects of DSM and distributed generation, T&D investments, new regulations such as new efficiency standards, or new technologies such as electric vehicles and air source heat pumps. As displayed in the early portion of the forecast the variation is narrower early on but then grows over time to reflect greater uncertainty in WEC's potential load.

Figure ES-2. Forecast of average monthly RTLO at different percentiles along the assumed cumulative probability distribution for each year of the forecast.[2]




For the Real Time Load Obligation (RTLO) forecast, the relative spread between potential loads from lowest to highest remains roughly constant through 2018. Thereafter, it changes by roughly 10 percentage points in both higher and lower loads per year to reflect ever-increasing uncertainty about WEC's system energy requirements in the future.

2 This forecast is adjusted to remove load served by GMP Wholesale Rate W, as this is not included in the power supply planning simulation for purposes of determining market sales and purchases.

## Demand Side Management

On September 30, 1999, the Vermont Public Service Board issued an order that created an energy efficiency utility (EEU) to deliver Demand Side Management (DSM) or energy efficiency programs and services to electric consumers in the state. The contract to deliver these programs was awarded to Efficiency Vermont (EVT). The EEU is now mandated to deliver statewide DSM programs in the WEC territory. WEC works closely with the EEU and monitors is own internal offerings of value added DSM programs. WEC currently offers rebates for residential new construction which includes incentives above the EEU program. WEC has also implemented new programs for compliance with a newly enacted Renewable Energy Standard (referred to as Button Up) as outlined later in this report. WEC works cooperatively with the EEU and others to delivery these programs.

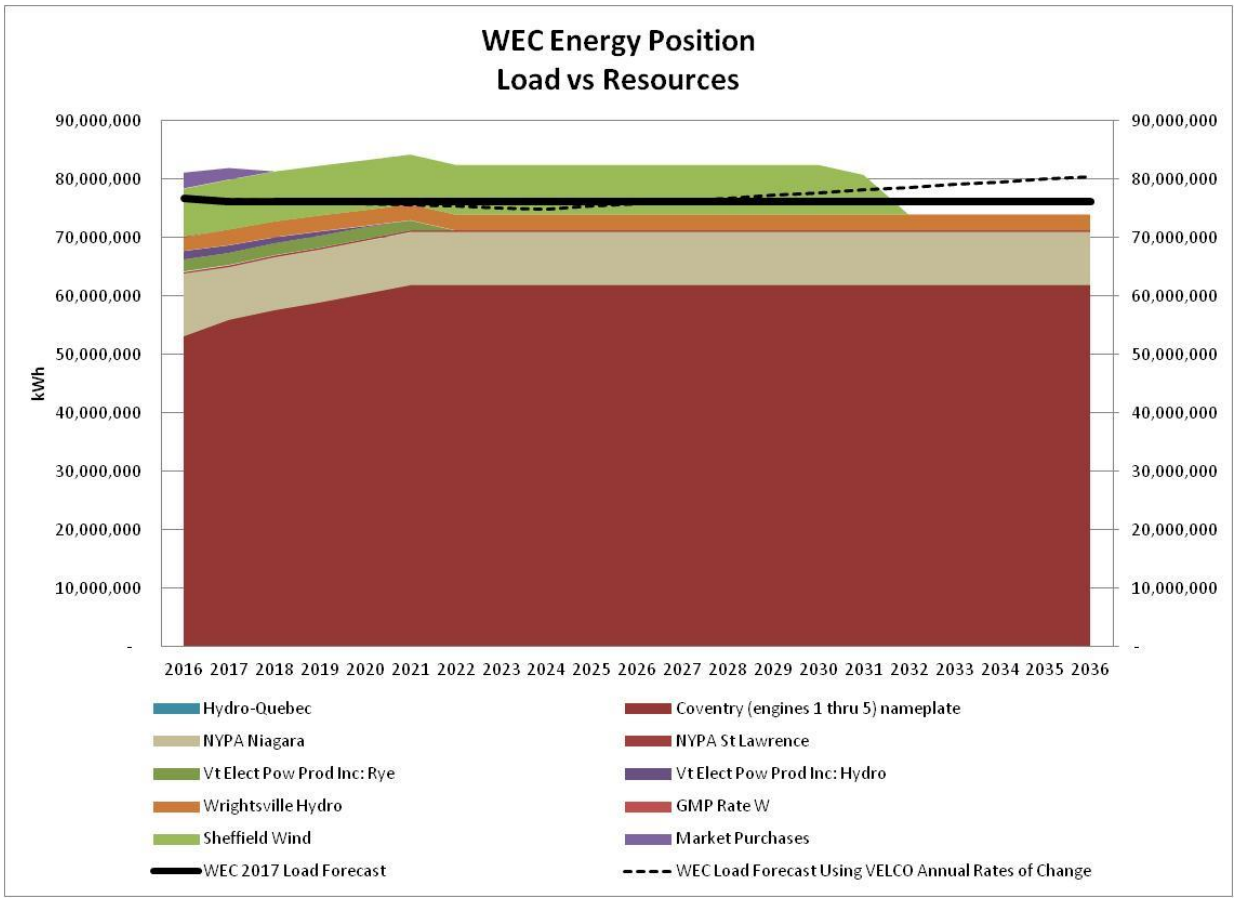
WEC will continue to coordinate with the EEU in the deployment of energy efficiency services to all its members. In addition, WEC participates in the Vermont State Planning Committee (VSPC), contributing feedback relative to forecasting and geo-targeting efforts in conjunction with EVT, Vermont Electric Power Company (VELCO), and the other Vermont distribution utilities. These relationships help ensure that WEC and Vermont stakeholders are apprised of DSM efforts, forecasting practices, and other energy issues in Vermont and regionally. In addition, participation assists with the coordination of information exchange among stakeholders.

## Power Supply

The power supply section of the IRP reviews and simulates costs for WEC's existing committed mix of resources. The power supply modeling is a tool that helps WEC to identify the need for upcoming supply decisions and to measure the impacts of those decisions based on cost, cost variance and emissions in WEC's projected resource portfolio scenarios.

Potential market, operating, and regulatory scenarios were created for three WEC supply portfolios, reflecting the possibility for differing resource availabilities, and alternative operating and regulatory environments. In large part, this scenario-based portfolio approach reflects the fact that WEC's committed supply resource mix leaves it in a long or excess position relative to its energy needs for almost the entire planning period. Therefore, WEC is well covered by its existing power supply commitments for its energy needs for the next 20 years. This relationship is clearly displayed in Figure ES-3.

Figure ES-3. Forecast of WEC Annual Energy Position over the IRP Planning Horizon




The IRP modeling tests the effects on portfolio costs, cost variance, and emissions, under different market conditions, using simulation software. Variants of key variables were evaluated based on the results of simulations conducted to test how the power supply portfolio responds assuming three different scenarios and varying market conditions.

The objective was to determine how the existing portfolio responds with changes to key variables assuming many combinations of the variables. Understanding the volatility in costs and identifying which key variables impact WEC the most is an important tool to help manage resources in the near and long-term more effectively. This process helps WEC assure it is positioned to provide its members with cost-effective power supply and stable rates, as well as safe, reliable, and environmentally responsible service.

The first step of the process was to determine the most significant external factors that affect WEC's power supply costs. These factors included members' consumption patterns, the

state and national economic climate, natural gas and other fuel markets, state and federal legislation and regulations, wholesale electricity market rules, etc. How these factors were modeled and projections developed are addressed further in Section 2 of the IRP.

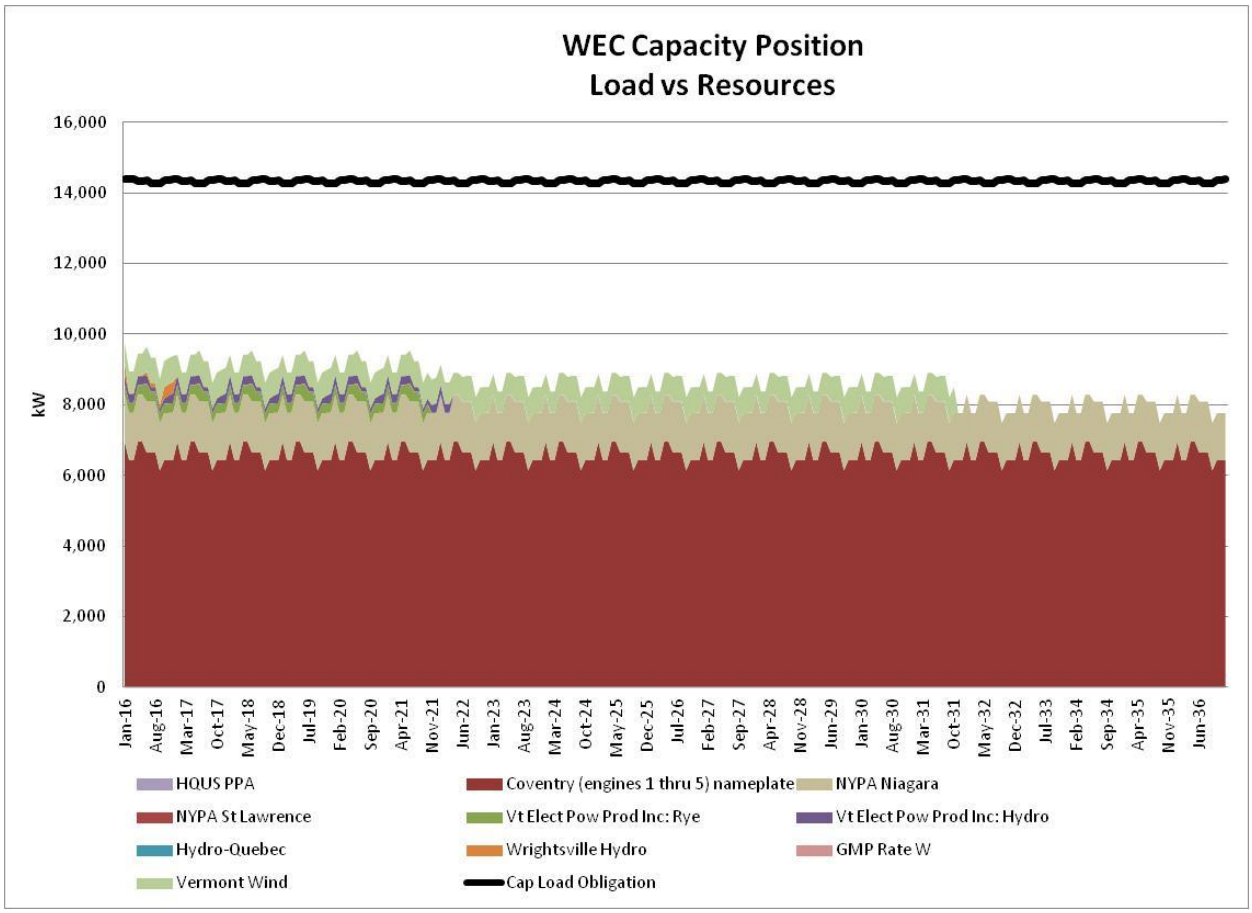
The second step required analysis of the effect of alternative load forecasts to determine WEC's total resource needs on a monthly basis through the 20-year planning period. As explained further in Section 2, monthly reference, high and low load forecasts were developed for both system energy and peak demand, and for each of the major member classes on the WEC system (residential and seasonal, small commercial, public buildings, and large commercial/industrial). The system energy and peak forecasts used in IRP simulations, like the underlying member class consumption forecasts; all represent a blend of shorter-term and longer-term forecast methodologies.

The third step assessed WEC's current resource portfolio as compared to the total forecast requirements, after making adjustments for DSM impacts to the load forecasts to arrive at a projected energy excess or shortfall by month. As Figure ES-1 reveals, WEC's energy position is well hedged through the planning period.

It is assumed WEC will not replace some of the expiring HQ contract energy with the new Hydro Quebec US Purchase Power Agreement (HQUS PPA) contract in the near term. WEC cannot access power from the HQUS PPA contract under a companion arrangement which is presently used by Vermont Electric Cooperative until WEC has a shortfall in energy. At this time WEC does not have need to take power back to cover its needs (more discussion on this can be found in Sections 2 and 3).

WEC has a capacity market need of roughly 40% for the foreseeable future. WEC has three options to manage this open position: lower load, increase supply, or a combination of both. Finding capacity (by contract or to build) to fill the shortfall has been unfruitful thus far. Investments in resources represent a long-term need and the cost to build is higher than the future capacity prices. In the short term, this is a financial risk factor for WEC. Through reduced load from load reducers and other internal generation sources, WEC may be able to mitigate some of the risk. Also, the outlook for capacity prices past 2020 remains uncertain as load regionally is falling, which may put downward pressure on the need and price.

Figure ES-4. Forecast of WEC Annual Capacity Position over the IRP Planning Horizon




The fourth step was to identify appropriate resource portfolio scenarios that could occur in the future. In this step, WEC develops cost projections using estimates associated with specific alternative market, operating and regulatory scenarios. These alternative portfolio and operating scenarios are summarized in Section 2.

The IRP analyses discussed and explained herein show that WEC will meet its power supply goals with its current resource portfolio, which contains a strong contribution from renewable energy resources, and potentially other DSM, distributed generation resources, and T&D investments.

## Legislative and Regulatory Directives

WEC outlines in its IRP the impacts of major new legislation and identifies how it plans to comply with significant directives. The IRP will answer how WEC plans to comply with

two major initiatives: Act 99, which addresses net metering, and Act 56, which addresses the renewable energy standard. WEC will also explore issues of a modern electricity grid in which demand fluctuates in new ways due to the build out of more resources like solar and wind. WEC will also take into account storage and energy efficiency in its outlook of the future.

As noted in the 2016 Comprehensive Energy Plan, utilities should use the IRP process to address questions that are the most relevant to the utility at the time of the IRP. WEC has designed this IRP to focus on various regulatory and policy directives. WEC will focus on areas such as Act 56 Renewable Energy standard, Act 99 net metering, and impacts of distributed generation on the T&D systems. In Section 4 of the IRP, WEC identifies and provides updates to major legislative and regulatory directives that it is monitoring.

## Transmission and Distribution

Section 5 reviews WEC's transmission and distribution plans for improving its system to enable the reliable and efficient provision of electricity to its members. WEC evaluates individual T&D circuits for the optimum economic and engineering configuration while meeting reliability and safety criteria. In this section, WEC outlines how and when the utility updates its planning for T&D and it provides a scoping analysis to assess the impacts of grid modernization such as increased penetration of distributed generation.

WEC receives financing from the Rural Utility Service (RUS) for its electrical system improvements. One of the requirements for RUS borrowers is the periodic development of a Construction Work Plan (CWP). The CWP is developed and written in accordance with the RUS and State of Vermont IRP guidelines, and serves as a foundation for the T&D element of the IRP.

## Action Plans

Section 6 is devoted to a discussion of action plans. The IRP is a planning tool that helps guide WEC and frames the direction it intends to head in the future relative to power supply and other major capital investments. It is not intended to be a fixed and prescriptive outline of what WEC will do next, but rather a dynamic and evolving planning tool to help inform and guide WEC decision-making. Consistent with Vermont's statutory policy, WEC will use the IRP as a key component in the development of its own strategic plan and understanding of changing needs to deliver power consistent with its member's interests and policies of WEC.

WEC's objective is to develop plans that support the following goals:

- Maintain financial strength and assure economic equity for members;
- Improve performance of WEC's distribution system for the benefit of members and provide access to local generation sources in WEC's service territory;
- Manage power supply, distribution, and transmission service at lowest cost, with consideration for environmental impacts and social concerns;
- Promote responsible environmental practices at WEC and assist members in achieving this goal;
- Maintain strong member, community and government relations in a changing environment; and
- Maintain strong organizational, administrative, and communication services.

As discussed in Section 6, WEC's action plans endeavor to meet the above goals and achieve balance among competing interests. WEC seeks to provide and deliver high quality and affordable electric service to its members consistent with good environmental stewardship. The portfolio WEC developed and the action steps identified to strengthen it reflect tradeoffs between meeting various goals and satisfying its members' needs.

# 1. Overview and Framing

## 1.1. About Washington Electric Cooperative

Washington Electric Cooperative, Inc. (WEC) is a not-for-profit member-owned rural electric utility established in 1939. Its approximately 11,000 members are spread over 2,728 square miles, in 41 towns and four counties (Washington, Orange, Caledonia, and Orleans) in north-central Vermont. Washington Electric Co-op's system was energized on December 2, 1939, bringing power to 150 farms and homes over 55 miles of distribution line. Today, the Cooperative serves over 11,000 members, 94% of whom are residential consumers. It operates approximately 1,200 miles of distribution line, with eight substations.

Founded to bring electricity to rural Vermont communities and to provide its members with a voice in their energy future, Washington Electric Co-op today unites our founders' pioneering spirit with a commitment to environment, our communities, and to our member/owners. As part of its mission, WEC is committed to:

- Providing energy to members as inexpensively as possible;
- Providing energy from clean and renewable sources;
- Helping members use energy efficiently and wisely;
- Providing reliable and safe service throughout our rural territory;
- Involving, informing, and educating our members; and
- Providing leadership and taking proactive positions on energy and environmental issues.

These guiding principles are at the core of WEC's decision-making.

## 1.2. WEC Membership Demographics

WEC's membership is comprised of several varying groups but WEC primarily serves homes and residences. Based on the number of 2016 members, 94% are residential and seasonal while roughly 6% of the membership consists of commercial or business-driven electric use.

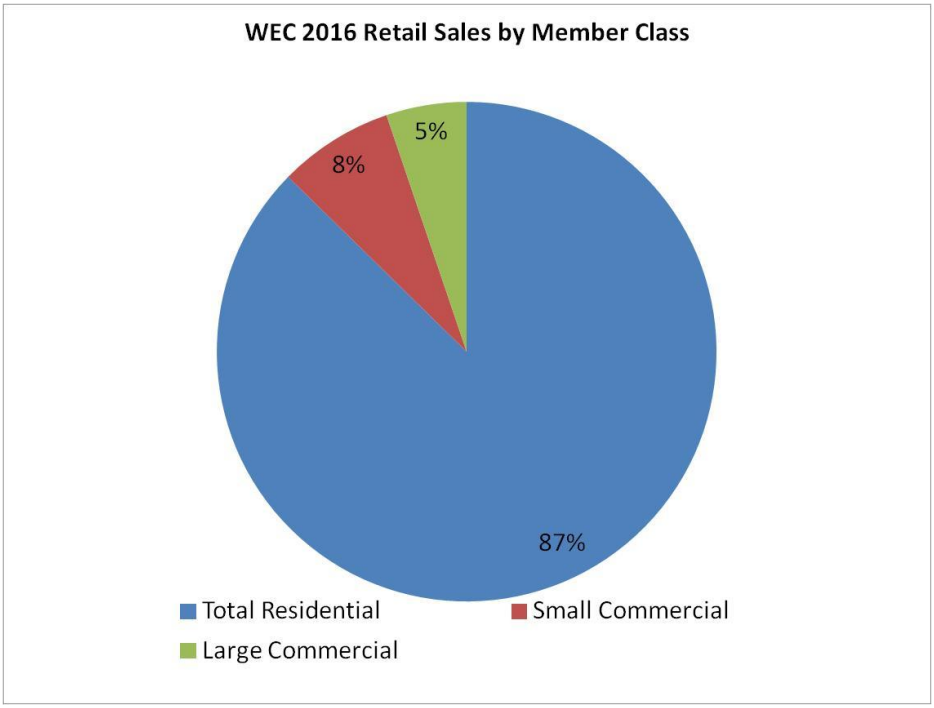
Table 1-1 summarizes the number of WEC's consumer-owners from 2016 by member class.

Table 1-1. WEC Member Distribution by Class

| Member Class | 2016 Members | % of Total |
|---|---|---|
| **Residential (incl. Seasonal)** | 10,381 | **94%** |
| **Small Commercial** | 622 | **6%** |
| **Large Commercial** | 12 | **0.1%** |
| **Total** | **11,015** | **100%** |

As measured on an energy basis, WEC's retail energy sales are overwhelmingly residential (and seasonal residential): about 87%.[3] WEC also has small commercial and large power sales (schools, office buildings, and light manufacturing) making up the remainder, about 8% and 5% of the total, respectively. See Figure 1-1 for a graphic summary of WEC's retail sales by membership class.

Figure 1-1. WEC Retail Sales 2016

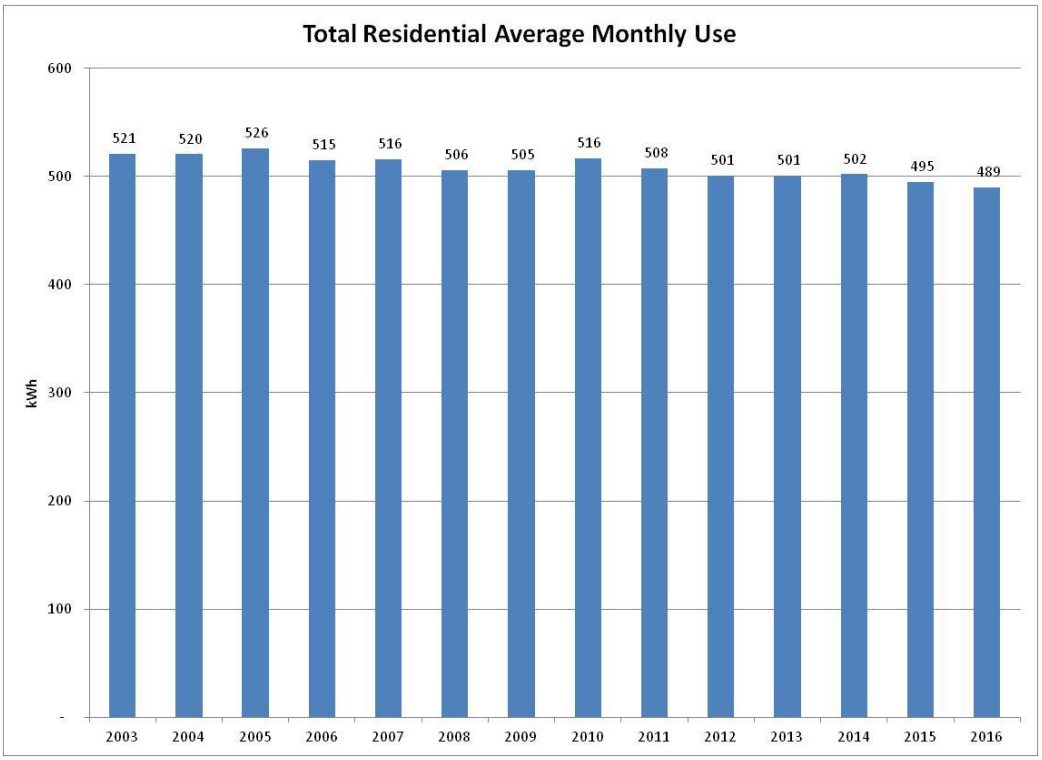



Member growth (from additional new members and conversion from seasonal to year round residences) has been responsible for most of any increase in WEC sales. However,

[3] Note that some dairy farms are included in the residential rate class. These members may have larger loads than the average single family home thereby skewing the data slightly for this sector.

WEC's average monthly usage per residential/seasonal member is steadily declining. It was 521 kWh in 2003, 516 kWh in 2007 and 489 kWh in 2016. The general declining trend in kWh/month/member consumption since the 1990s reflects the slowdown in the Vermont economy and the longer-term success of the Co-op's and the state's demand side management programs, plus new federal energy efficiency standards and the highly successful net metering program. WEC's overall retail sales have decreased in the past several years, with a compound annual average growth rate of - 0.084% since 2010. Figure 1-2 summarizes this trend graphically.

Figure 1-2. WEC Residential Monthly Consumption Trend




## 1.3. Overview of WEC Service Territory

As displayed in Figure 1-3, WEC operates in a large and dispersed geographic area. Many of the communities WEC services are some of the most rural in the state of Vermont. The figures below portray WEC's service territory in relation to state boundaries. WEC has the least dense system of any Vermont utility in the state, with an average of eight members per mile of electrical distribution service. WEC's service territory is comprised of mostly unpaved roads. While a portion of WEC's lines run along roads, a significant portion is not. Most of WEC's lines run through rugged and challenging terrain. WEC members were some of the last to receive electricity in the state due to the area's remoteness, low populations in the towns, and the

expense to build infrastructure. Prior to the Co-op's formation, the people in our towns were simply left without electricity.

Figure 1-3. WEC Service Territory



## 1.4. Organization Mission, Governing Board, Benefits of Membership

Washington Electric Cooperative's mission remains essentially the same today as when it was founded almost eighty years ago: to provide affordable access to electric power and energy-related products and services for area residents and our communities, through a consumer-owned and locally-controlled cooperative business. As part of that mission, WEC is committed to meeting the following responsibilities:

- Educate and advise its members about using energy safely, wisely, and economically;
- Keep its member-owners informed about their Co-op and its business, economic, regulatory, political, and social environments;
- Minimize the environmental impacts of electric generation and our operations;
- Support and promote our local economy and community organizations;
- Provide leadership and speak out on energy and environmental issues; and
- Construct cost-effective renewable generation close to load.

The business and affairs of the Cooperative are managed by a Board of nine Directors. At each annual meeting of the members, three Directors are elected to serve a term of three years. The Board of Directors holds regular monthly meetings and the meetings are open to members. In addition to being part of a not-for-profit member owned entity, members benefit and can participate in WEC business matters in several ways:

- **Vote on large long-term power supply contracts:** Under Vermont statutes regulating electric cooperatives, WEC in certain situations, is required to hold a vote of the membership before instituting large and long-term contracts for power generated outside the state. These are defined as contracts of five years or longer, and for power that would constitute more than 3 percent of WEC's peak demand and which is not from renewable sources of power.[4]
- **Vote on major capital expenditures for generation and transmission facilities**: WEC must ask its members' approval of plans to build and construct generating stations and to make major capital expenditures on new transmission facilities. The Coventry landfill facility, which is fueled by landfill methane and which now provides two thirds of WEC's power supply, is an example in which members voted for and approved investing in a major capital expenditure.
- **Attend Board meetings**: Meetings of WEC's Board of Directors are generally held on the last Wednesday of each month, beginning at 5:00, at the member services office off Route 14 in East Montpelier. Meetings are open to members.
- **Run for the Board:** Any qualified member can join the Board if voted in by the membership. Serving on the Board of Directors allows a member to shape policy and organizational decisions of the Co-op and serve the needs of the entire membership.
- **Receive capital credit distributions**: Washington Electric Cooperative is a not-for-profit company. In years when the Co-op's revenues exceed its expenses, those excess dollars, or "margins," are assigned (also known as allocations) to capital credit accounts held in each WEC member's name. These are bookkeeping entries, not actual cash accounts. In 1998, WEC became the first electric co-op in the state to begin disbursements of money (referred to as retirements) to its members, based on values documented in their capital credit accounts. With some alteration—for example, the disbursements for most people now take the form of credits on their November electric bill—it has continued that practice every year since.

---

[4] . A certificate of public good and vote of the membership is required for some contracts based on the amount being purchased and duration of the agreement. See 30 V.S.A. § 248(a)(1).

Table 1-2. Capital Credit Retirements

| Year | Dollars Given Back to Members |
|---|---|
| 1998 | $ 273,173 |
| 1999 | $ 231,221 |
| 2000 | $ 287,695 |
| 2001 | $ 221,316 |
| 2002 | $ 203,241 |
| 2003 | $ 204,649 |
| 2004 | $ 277,129 |
| 2005 | $ 275,010 |
| 2006 | $ 272,815 |
| 2007 | $ 276,258 |
| 2008 | $ 318,221 |
| 2009 | $ 275,006 |
| 2010 | $ 272,999 |
| 2011 | $ 275,025 |
| 2012 | $ 275,329 |
| 2013 | $ 274,949 |
| 2014 | $ 299,992 |
| 2015 | $ 349,996 |
| 2016 | $ 460,001 |
| Total | $ 5,324,023 |

In total WEC has returned $5.3 million to its members. WEC's annual retirements are summarized in Table 1-2. In 2016, WEC returned $460,000, which is roughly equivalent to a three percent reduction in rates. Therefore, each year members see a reduction in their electric bills that can help offset the impact of years WEC must increase rates. The return of capital credits is unique to the co-op model and is a way to reinforce the ownership value in a member-owned utility. Neither municipal nor private utilities in Vermont return dollars to their rate base in the form of annual credits or checks.

## 1.5. 2015 Member Satisfaction Survey

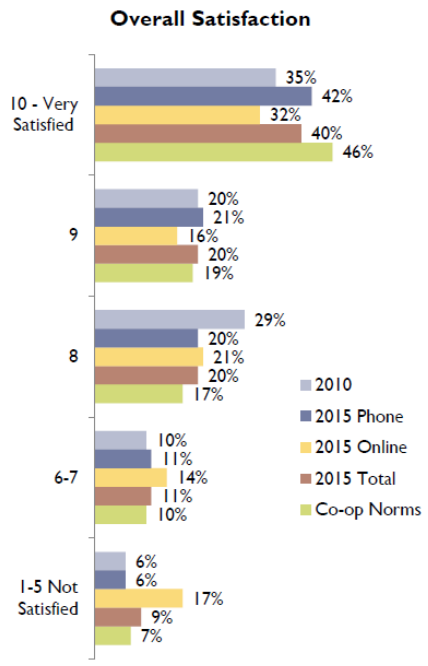
Every five years WEC conducts a survey of a representative sample of its members. WEC last surveyed members in 2015; the previous survey was completed in 2010. The results of tracking surveys provide value in two ways: by demonstrating when results remain consistent, and by indicating where there has been significant change over time. As noted by the firm

carrying out the survey on WEC's behalf, the Co-op experienced events that are likely to have an impact on members' attitudes and satisfaction:

- The Co-op raised rates in July 2014 by 3.78%;
- The Co-op introduced solar hot water installations and online credit/debit payments in 2013;
- The area experienced a 10-day storm in December 2014 during which up to 55% of the membership was without power.

Overall satisfaction among WEC's residential members is very good. The mean overall satisfaction rating is 8.49 on a 10-point scale, and 60% give ratings of "9" or "10".

Figure 1-4. Overall Satisfaction Survey Results




Members were asked to evaluate nine attributes of service regarding both importance to the member and WEC's performance in each area. On all but one of the attributes measured, the mean ratings for importance were near or above 9.00 on a 10-point scale, indicating very high importance.

The mean ratings for how well WEC is meeting expectations on each attribute vary. Members gave the highest importance ratings for providing reliable service and having competent and knowledgeable employees. Performance ratings for both of these attributes

were also very high, with means near 9.0. The lowest rating for both importance and performance is for helping members learn to manage their energy use.

Table 1-3. Satisfaction Ranking by Key Attributes

| | Importance | | Performance | | Gap - Difference Between Mean Importance and Performance |
|---|---|---|---|---|---|
| | Mean Rating | Rank | Mean Rating | Rank | |
| *Providing reliable service* | 9.66 | 1 | 8.85 | 3 | 0.81 |
| *Having competent and knowledgeable employees* | 9.56 | 2 | 8.98 | 2 | 0.58 |
| *Handling individual complaints and problems* | 9.36 | 3 | 8.62 | 4 | 0.74 |
| *Being friendly and courteous in the service they provide* | 9.35 | 4 | 9.06 | 1 | 0.29 |
| *Providing a good value for the money spent* | 9.35 | 5 | 7.85 | 8 | 1.50 |
| *Looking out for members' best interests* | 9.19 | 6 | 8.04 | 7 | 1.15 |
| *Communicating with members and keeping them informed* | 9.03 | 7 | 8.45 | 6 | 0.58 |
| *Being committed to the community* | 8.96 | 8 | 8.48 | 5 | 0.48 |
| *Helping members learn to manage their energy use* | 8.11 | 9 | 7.43 | 9 | 0.68 |

Cost, as measured by the response to value for the money spent, was ranked 5$^{th}$ out of nine key attributes. WEC expected cost to rank higher, especially following a recent rate increase. But the results clearly show that members want reliable service first and foremost, followed by knowledgeable, competent, and courteous employees. A complete copy of the survey is in the Appendix.

## 1.6. Power Supply Situational Analysis

WEC has a diverse portfolio of power contracts and resources it uses to cover its load requirements, which have been flat to slightly declining for the past several years. WEC remains well positioned long-term to hedge against changing loads and volatile power market

prices through stably-priced contracts and owned generation resources.

In fact, WEC's 2017 IRP filing is not analyzing the need to replace or enter new long-term power commitments. WEC's 2014 IRP, the Co-op completed a rigorous resource analysis in which it analyzed various portfolios and stress tested the assumptions used to calculate costs. Given that little has changed in terms of WEC's power supply commitments since the 2014 filing, WEC concluded that completing the same analysis for the 2017 filing will not yield new results; the issues that were key drivers to WEC in 2014 remain salient today.

As a result, WEC is submitting its 2017 IRP using an update of its current position and recalibrating its outlook of projected load. WEC will use this information to help plan for its projection of when the Hydro Quebec contract may be needed. It will also be used to evaluate the outlook of its long-term resources and key drivers impacting those resources.

On March 31, 2014, WEC filed with the Vermont Public Service Board its 2014 Integrated Resource Plan, which was ultimately approved in Docket 8181. In a Memorandum of Understanding reached with the Department of Public Service, as part of its filing on March 31, 2014, WEC agreed to fourteen conditions (see MOU in Appendix section). Some of the key conditions that are addressed in this IRP are noted below, and WEC agreed to continue its ongoing duty to:

a) Meet with the Department periodically prior to and during the development of its next IRP (item 5);
b) Monitor key uncertainties and the continued accuracy of assumptions and data in the IRP (item 7a);
c) Continue to reevaluate the merits of the decision-making processes, including but not limited to the analytic methods used, and to adapt such processes to new techniques or information (item 7b);
d) Continue to reevaluate the merits of its decisions (item 7c);
e) Engage the Department in developing its 2014-2017 Construction Work Plan (item 8)

The above are a partial subset of conditions of the MOU that are explicitly called out in this IRP. Appendix includes a complete copy of the MOU. WEC agreed to file its next IRP on or before April 1, 2017. In order to allow for more time to work with the Department to review WEC's work on the 2017 IRP, an extension was requested to July 31, 2017. This document

fulfills this filing requirement.

## 1.7. WEC 2017 IRP Focus and Regulatory Requirements

Pursuant to 30 V.S.A. §218c each regulated electric utility is required to prepare and implement a least cost integrated plan (also called an integrated resource plan or IRP) for provision of energy services to its Vermont customers. The Vermont Electric Plan and Public Service Board ("PSB" or "Board") Orders outline requirements that a distribution utility's complete IRP should meet in order to obtain the Department's and Board's approval.

As stated above, the IRP process and the implementation of each Vermont utility's approved plan are intended 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 (30 V.S.A. §218c). The cost and benefit factors to be considered include both direct monetary costs and benefits, and indirect impacts such as environmental and other societal effects.

In addition, as part of the 2016 Vermont Comprehensive Energy Plan, an addendum related to IRP planning and guidelines were prepared by the Vermont DPS. This document outlines key components of an IRP and provides guidelines to utilities as they carry out their planning. WEC completed its present analysis and IRP report with the IRP guidelines and 2016 CEP in mind. The guidelines do not lay out a prescriptive basis as to how to do IRP planning and analysis. Rather, the DPS addendum provides a guide for completing IRPs consistent with state statute VSA §218c covering Least Cost Integrated Planning and the Vermont Comprehensive Energy Plan. The guidelines recognize the ultimate content and organization of an electric distribution utility's plan will be unique to each individual utility.

As noted in the 2016 CEP, utilities should use the IRP process to address *questions that are the most relevant to the utility at the time of the IRP* (emphasis added). WEC met with the Department in advance of the filing to discuss its key issues and questions it desired to address in this filing. WEC and the Department agreed that since WEC is not making large or long-term power supply decisions for the next several years, its IRP will focus on key issues identified by WEC rather than carrying out a new power cost simulation and modeling efforts.

As a result, WEC's IRP is structured to focus on the following areas WEC believes are key issues:

- Revisit key power cost drivers from 2014 IRP analysis and reaffirm relevance of each driver to WEC's current situation and costs;
- Assess ways to control costs and pressure of increasing rates in light of flat to declining load;
- Review FERC relicensing effort for Wrightsville hydro station;
- Provide an overview of important regulatory drivers
    - Act 56 Renewable Energy Standard,
    - Act 99 Net Metering,
    - 2016 Comprehensive Energy Plan;
- Assess impacts of distributed generation to the T&D systems.

In this IRP, WEC will provide updates to the major risk elements identified in the 2014 analysis, and the IRP will focus on issues germane to WEC in the next five years. WEC sees its largest question as pertaining to future impacts of changes to demand and grid modernization. Increased deployment of distributed generation are moving WEC's energy, peaks, and revenue down while cost pressures from transmission and capacity markets are driving costs up. WEC will explore ways to be sustainable and serve members' needs in an industry moving toward rapid deployment of smaller distributed sources of generation and increased uncertainty of load. WEC looks to rate design and storage as a potential means to keep rates and bills to members stable while minimizing subsidization between customer classes.

In order to keep electric rates and bills affordable, while maintaining environmental considerations and advancing WEC and statewide goals, WEC will explore new ways to lower peak use at the time of the ISO-NE peak. Flattening WEC's load shape and minimizing seasonable fluctuations where possible can also potentially help manage costs. WEC will also explore ways to reduce regional load while maintaining revenues (such as exploring use of load reducers from internal generation sources) as a way to mitigate rate pressure. Rate design and analysis of WEC's cost of service may also help stabilize member bills and address a current dependence on obtaining revenue from the variable component or kWh sales.

Consistent with previous Board decisions, including WEC's IRP in docket 7432 and docket 8181, WEC seeks approval of its 2017 IRP. Approval extends to the decision-making process, but not to specific decision-making tools, analytical methods, or outcomes described in the IRP herein. This is consistent with previous Board decisions regarding the scope of approval of an

IRP. WEC seeks similar approval in this filing.

**Load Forecast:**

WEC and the Department agreed that a new load forecast would yield minimal new information. Plausible futures of WEC's load were simulated in a rigorous scenario analysis (in which load was varied in a Monte Carlo [5] analysis exercise) completed in the 2014 IRP. This analysis captured potential outcomes of WEC's load in the near term and over the 20 year planning period. WEC notes that its customer demographics haven't changed since that load forecast. Also, WEC's load has been flat to declining in the past three years due to distributed generation, robust efficiency efforts, and consumer behavior.

Given WEC's dominant residential demographic, it is not likely that load will change considerably in the upcoming five years. Therefore, WEC updated the 2014 load forecast with current information to provide an outlook for the upcoming 20 years based on knowledge of variables likely to change WEC's load. As a secondary check, WEC contrasted the outlook to VELCO's load forecast reported in the 2016 CEP. WEC will report in the current IRP how accurate the 2014 load forecast was relative to actual load and make adjustments to the outlook based on this information.

**Power Supply:**

Included in the power supply section are updates to all generation resources and power contracts. Due to the rigorous Monte Carlo work in the 2014 IRP, WEC does not expect appreciable change in the results and its outlook of major factors affecting its costs; the key variables and costs identified in the 2014 IRP remain relevant to today's situation and analysis.

WEC is not making large or longer-term power supply decisions for the next several years. Therefore, the value of another rigorous power supply centric analysis is of minimal benefit for future decision-making. Production projections will be based on current information and contract terms and information relevant to projected energy production of each resource. WEC will use this IRP analysis to project its need for the HQUS PPA "take back" from VEC.

---

[5] Monte Carlo simulation modeling is a software based simulation tool that is used by decision-makers to answer key questions such as what are the effects to WEC if certain conditions occur. It is used to approximate the probability of certain outcomes by running multiple trial runs, called simulations, using random, distribution defined, and potentially correlated, variables for key inputs into the analysis. The results of numerous trial runs are stored and the outcomes graphed, usually with a frequency distribution, in order to provide a probabilistic assessment of outcomes based on predefined distributions of key input variables.

**Legislative and Regulatory Directives:**

WEC outlines the impacts of major new legislation and identifies how WEC plans to comply with these significant directives. The 2017 IRP answers how WEC plans to comply with two major initiatives: Act 99, which addresses net metering, and Act 56, which addresses the renewable energy standard. WEC also explores issues of a modern electricity grid, in which demand fluctuates in new ways due to the build out of more resources like solar and wind. WEC also takes into account storage and energy efficiency in its outlook.

**Distribution System:**

WEC receives financing from the Rural Utility Service (RUS) for its electrical system improvements. Therefore, it must address additional long-term planning requirements to satisfy the needs of its lenders. One of the requirements for RUS borrowers is the periodic development of a Construction Work Plan (CWP). The CWP is developed and written in accordance with the RUS Bulletin 1724D-101B guidelines.

An important question to WEC, and a key driver of this IRP, relates to impacts of distributed generation and fluctuation to load on WECs T&D system. In this IRP, WEC outlines big picture questions that will drive T&D analysis in the future, relative to a modern grid. WEC frames key questions relative to impacts on T&D from consumer-centric forces.

In its T&D write up, WEC looks to do a system analysis and analyze impacts on the T&D system as follows:

- Evaluate benefits of circuit load forecast in conjunction with next CWP (CY 2017);
- Identify a scoping process for work to be done over the next five years
    - Plan for circuit analysis
    - Integrate in our next CWP (file in 2018)
    - Prepare a circuit and system load forecast for this effort;
- Explore distributed generation and solar impacts on our grid
    - How much can the WEC grid handle?
    - Does volume of distributed generation matter by circuit?
    - Explore GMP solar mapping with GMP staff to see if WEC can use their early research to help guide our analysis
    - Map out best and worst locations for distributed generation.

WEC's current CWP, dated May 2014, covers the period from 2014-2017. This plan is still active, with RUS approved projects scheduled into 2017. In advance of completing the current CWP, WEC is developing a new plan that will cover the period from late 2017-2020. The completion of WEC's current CWP is on schedule.

The requirements of the CWP are laid out by RUS and are summarized as follows:

> The Construction Work Plan process is used to determine and document a borrower's 2 to 4 year construction needs that are the most feasible, environmentally acceptable and economical. New construction is periodically required in order to provide and maintain adequate and reliable electric service to all of a system's new and existing members. The CWP should include all recommended electric plant facilities regardless of the financing source (general funds, RUS, or all other lenders). A CWP is a valuable reference for the preparation of annual construction budgets and schedules. The CWP report is also used as an engineering support document for a loan application to finance a proposed construction program. As such, the CWP is used as a means to inform RUS and receive RUS's approval of proposed new construction items (from RUS Bulletin 174D-101B, page 3).

In summary, WEC has prepared its IRP consistent with regulatory guidelines provided by both the state of Vermont and the RUS. The IRP process is intended, in part, to facilitate information exchange among WEC and its members, regulatory agencies, and the public. As part of that effort, WEC held several meetings and discussions with DPS staff at varying times to report and update on its progress while preparing the IRP. WEC is confident this report is consistent with current regulatory requirements and goals as requested by the State of Vermont.

## 1.8. Objective of an IRP

Vermont Statute 30 V.S.A. § 202a states the purpose of the Energy Policy of the State of Vermont as follows:

> (1) To assure, to the greatest extent practicable, that Vermont can meet its energy services needs in a manner that is adequate, reliable, secure and sustainable; that assures affordability and encourages the state's economic vitality, the efficient use of energy resources and cost-effective demand side management; and that is environmentally sound.
>
> (2) To identify and evaluate on an ongoing basis, resources that will meet Vermont's energy service needs in accordance with the principles of least cost integrated planning; including efficiency, conservation and load management alternatives, wise use of renewable resources and environmentally sound energy supply.

There are many stakeholders involved in the electric utility world. In the case of an electric cooperative such as WEC, the major stakeholders are its consumer-owner members, Board of Directors, regulators, and the management and staff of the utility. The IRP process provides information to these groups to support resource management decisions necessary to manage the cost and reliability of the WEC system and to do so in compliance with regulatory requirements.

The IRP has been referred to as Least Cost Integrated Planning. However, to WEC it is much more. WEC views its IRP as a strategic and informative planning tool that provides WEC stakeholders information on the costs, risks and other impacts of resource portfolio choices. WEC's IRP contains a combination of situational analysis, numerical analysis, risk analysis, and the exercise of judgment. WEC utilizes the IRP to evaluate, based on resource planning principles, different supply resource options alongside alternatives that reduce members' consumption. In addition, the IRP helps inform WEC's stakeholders of its preferred resource plans for the future and its rationale for following a particular strategy.

The IRP frames WEC's future direction relative to power supply and other major capital investments. It is not intended to be a fixed and prescriptive outline of what WEC will do in any particular situation, but rather a dynamic and evolving tool to help inform and guide WEC decision making. The IRP measures and analyzes how various resource options and plans are projected to perform in any number of future market environments, and how well such plans satisfy WEC stakeholders.

WEC has prepared its IRP to satisfy state rules, goals, and directives. WEC also uses the IRP as a key component in the development of its own strategic plan.

WEC's objective is to develop plans that support the following goals:

- Provide energy to members as inexpensively as possible;
- Maintain financial strength and assure economic equity for members;
- Improve performance of WEC's distribution system for the benefit of members and provide access to local generation sources in WEC's service territory;
- Manage power supply, distribution, and transmission service at lowest cost, with consideration for environmental impacts and social concerns;
- Promote responsible environmental practices at WEC and assist members in doing so;
- Maintain strong member, community, and government relations in a changing

environment; and

- Maintain strong organizational, administrative, and communication services.

These goals may not be independent of one another. Potential solutions to achieve one goal may be counter-productive to other goals. The portfolio WEC developed will reflect tradeoffs between various goals.

The IRP outlines action plans that are robust under a variety of possible future scenarios. It is intended to be a working document, used to inform the day-to-day and long-term decision-making process throughout WEC. It will be used as a benchmark to ensure coordination between the various activities and practices of WEC so that operations are internally consistent and mutually supportive.

## 1.9. IRP Report Organization

The IRP is organized by sections and follows the following topical components:

Section 2. Resource Assessment & Load Forecast

Section 3. Committed Supply Resources & Projected Requirements

Section 4. Legislative & Regulatory Directives

Section 5. Transmission & Distribution System

Section 6. Action Plan

Section 7. Appendix

# 2. Resource Assessment & Load Forecast

## 2.1. Overview of Resource Modeling Approach

The intent of the IRP resource modeling process is to provide important information about the costs, features, and risks of various power supply portfolios that WEC could use in the future to meet its system load requirements. The goal is to project cost and cost variance, emissions profiles, and other measures associated with each portfolio, under a broad range of future loads, market prices, economic conditions, and other factors affecting performance, such as market or regulatory changes. The IRP process is used to develop methods to evaluate competing future investments and purchase decisions.

As noted in the IRP guidelines, "utilities should use the IRP process to address questions that are the most relevant to the utility at the time of the IRP." [6] Since little will change in WEC's resource outlook, this plan summarizes the results of the modeling from the prior IRP filing. WEC provides a summary in this section of that analysis and the results. For a complete description please refer to WEC's filing of its 2014 IRP.

## 2.2. Brief Introduction to the New England Power Markets

In this subsection, WEC describes the New England power markets in which WEC operates, products WEC sells as a generation owner, and products WEC purchases to meet its load. A summary of these markets provides a foundation for understanding the work carried out as part of the IRP.

WEC is part of and operates in the New England wholesale power markets, which are administered by the Independent System Operators of New England (ISO-NE). The ISO-NE is responsible for reliability of a regional power grid covering all six New England states, including Vermont. That grid includes more than 300 separate generating plants and more than 8,000 miles of transmission lines—all interconnected and dedicated to ensuring reliability of the New England region. The ISO-NE has three primary responsibilities:

[6] 2016 CEP, Appendix B; Guidance for Integrated Resource Plans and 202(f) Determination Requests, page 5

- Reliability: Minute-to-minute reliable operation of New England's bulk electric power system, providing centrally dispatched direction for the generation and flow of electricity across the region's interstate high-voltage transmission lines and thereby ensuring the constant availability of electricity for New England's residents and businesses;
- Cost-effective Markets: Development, oversight, and fair administration of New England's wholesale electricity marketplace, through which bulk electric power has been bought, sold, and traded since 1999. These competitive markets provide market-based economic and environmental outcomes for consumers;
- Planning: Management of comprehensive bulk electric power system and wholesale markets' planning processes that address New England's electricity needs well into the future.

**Spot Energy Markets**

Fuel prices, such as natural gas, and supply and demand conditions in the New England power markets determine the wholesale market price for electricity. Regional conditions and markets affect the cost of other power requirements, including capacity and ancillary services.[7] Consequently, the economic operation of any supply resource that WEC might consider as part of its future supply portfolio is a function of conditions in the wholesale fuel and electric generation markets.

Hourly Locational Marginal Prices (LMPs) are developed and published by ISO-NE for energy delivered at specific points or 'nodes' on the electric system where generation or load interties with the bulk power grid. LMPs for each node are established for two energy markets operated by ISO-NE: day-ahead and real-time. These markets are designed with the goal to achieve efficient economic dispatch of the regional generation fleet, subject to transmission security protocols and/or constraints. Each generating unit providing energy to the spot market at a given location (e.g., at the generator bus, or delivered into pool transmission facilities), in a given hour, receives a clearing price based on the LMP at that location. In general, the LMP reflects the bid price(s) of the most expensive source(s) providing energy to that location in that hour. Under this market structure, generation suppliers have incentive to bid at or near their short-run variable costs of providing energy.[8]

---

[7] Ancillary services include spinning reserves, regulation, and black start capability that certain generators offer to help keep the regional system operating reliably and safely.

[8] A supplier of generation bidding below its short-run marginal costs including fuel runs the risk of losing money on every kWh generated if the supplier's short-run marginal cost exceeds the market clearing price. A generation supplier bidding above

## ISO-NE Markets—Multi-Settlement System

The ISO-NE market system is a "multi-settlement" system, meaning there are separate settlements between ISO-NE generators and load-serving entities (LSEs). Specifically, ISO-NE pays generation based on nodal, hourly LMPs specific to their locations. In separate transactions with load-serving entities, ISO-NE charges load based on the aggregation of nodal LMPs into zonal averages depending on what state or section within a state the load resides. Therefore, all generation is paid and all load is charged for various markets and services to provide reliability of the grid.

The market is geographically segmented for pricing wholesale electricity relative to load. Pricing zones are established by state boundaries, and in some cases, further refined due to transmission constraints that limit the free flow of power between locations within a given state. There are eight ISO-NE energy pricing zones, or load zones: one for each of the states of Vermont, New Hampshire, Maine, Rhode Island, and Connecticut, and three within Massachusetts.

The economics of WEC's net cost to serve load are based on charges it incurs for load and credits it receives for its various supply resources. Therefore, WEC's costs depend specifically upon the Vermont zonal LMP average, which is charged to WEC load, as well as other products from ISO-NE administered markets. However, these costs are offset by revenues received for WEC's supply resources based on specific nodal LMPs, wherever they are located, and other market credits for power sources.

## Regional Energy Prices Modeling and the New England Energy Market

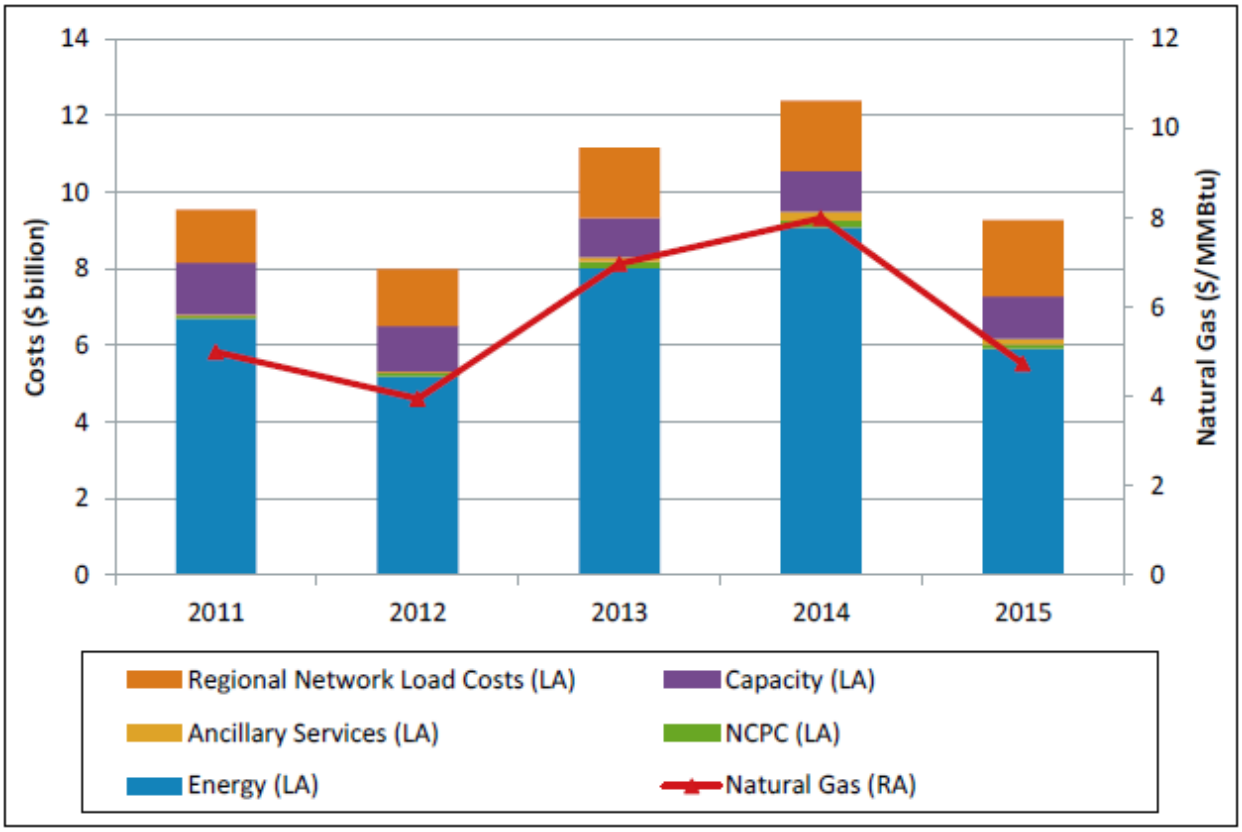
The energy market is the largest component of wholesale power costs in New England, accounting for approximately 64% of the total cost of charges incurred for load from the ISO-NE for energy, capacity, and ancillary service charges in 2015.[9] Energy prices as a share of total load costs are shown graphically in Figure 2-1. In WEC's IRP, regional energy prices were simulated based on assumptions contained in production simulation software. This model provides a representation of the electrical system of New England and neighboring regions. For more on the model, please refer to WEC's 2014 IRP.

---

its short-run marginal cost including fuel is at risk of not being dispatched, and thus foregoing opportunities to earn operating profits (i.e., revenues that exceed short-run marginal costs). Thus, it is assumed that most generation suppliers in the energy market would bid hourly energy prices in the day-ahead and real-time markets that approximate their short-run marginal costs.

9 ISO-NE, *2015 Annual Markets Report,* Figure 1-1, p.12, https://www.iso-ne.com/static-assets/documents/2016/05/2015_imm_amr_final_5_25_2016.pdf

Figure 2-1. Wholesale Market Costs and Average Natural Gas Prices




Data Source:
https://www.iso-ne.com/static-ssets/documents/2016/05/2015_imm_amr_final_5_25_2016.pdf

**Regional Network Load (RNL) Costs**

In 2015, Regional Network Load Costs were 21% of total costs of load. These charges represent the costs of transmission facilities, charges for reliability, and certain ISO-NE administrative services. Of the three cost categories included in RNL (infrastructure, reliability, and administrative), infrastructure costs make up over 90%. RNL costs rose by 8% in 2015 as a result of investment in new transmission infrastructure, upgrades to existing infrastructure, operating and maintenance costs, and other components impacting the overall revenue requirement.[10]

**New England Forward Capacity Market (FCM)**

After the energy and RNL markets, capacity is the next largest component of wholesale

[10] Ibid

power costs in New England, accounting for approximately 12% in 2015.[11] This market establishes the price ISO-NE must pay to generators for having a sufficient amount of installed capacity (also thought of as brick and mortar resources) which are necessary to assure system reliability under peak conditions.[12] Therefore, FCM can be thought of as a market to assure there are sufficient resources ready and able to operate to meet the maximum energy needs of the grid. FCM establishes the price ISO-NE charges to load to obtain revenues necessary to compensate generators for their installed capacity.

FCM clearing prices are established annually and three years in advance of the delivery period, based on auctions in which various generators and demand response resources bid their costs to supply capacity. The forward capacity auction clearing price is based on the highest bid price cleared in a reverse auction to procure enough capacity to meet ISO-NE projected peak demands in three years, plus reserves, for each planning year beginning in June and ending in May of the following calendar year.

In WEC's IRP study, FCM clearing prices were simulated based on the trend in regional forward capacity auctions, with additional uncertainty added to reflect ISO-NE's plans to transition from a single regional price to a locational market product with a potentially different price for Vermont capacity requirements.

**New England Ancillary Services Markets and Other Charges**

Ancillary Services and Net Commitment Period Compensation (NCPC) are the smallest component of wholesale power costs in New England, accounting for approximately 2% in 2012 and in 2015.[13] Ancillary services include:

- Spinning reserve capacity that can ramp up or down within specified time intervals in response to changes in load or other disruptions to the power grid;
- Regulation service provided by generators that balance supply with local demands over very short time intervals; and
- Black Start capability of generators that can be used to reenergize the power grid after a transmission line outage.

---

11 Ibid

12 Broadly speaking, capacity as a power product can be thought of as a call option on energy, and the costs of capacity are largely the fixed or capital costs associated with generating plants providing energy.

13 ISO-NE, *2015 Annual Markets Report,* Figure 1-1, p.12, https://www.iso-ne.com/static-assets/documents/2016/05/2015_imm_amr_final_5_25_2016.pdf

The cost of these products is paid by load-serving entities and is based on clearing prices for these services set in the ISO-NE ancillary services markets.

In WEC's 2014 IRP, ancillary markets were not specifically modeled. Instead, the IRP focused on the net costs to WEC for energy, capacity, regional transmission, and renewable supply requirements over the 20-year planning horizon. That said, WEC is seeing increases in its power costs due to the cost of ancillary markets, in particular from winter reliability charges, and it monitors these costs and the underlying causes through its participation in various ISO-NE committees. Maintaining an understanding of regional issues and changes in energy markets will allow WEC to understand the impacts it could see in the future from ancillary market charges.

### 2.3. WEC Resource Portfolios

In the 2014 IRP, WEC's existing supply resource mix was modeled using three different portfolio assumptions. The portfolios are explained below and summarized in Table 2-1.

Portfolio 1 (the "Status Quo," "Do Nothing," or "Base Case") assumed WEC does not secure any new power supply resources in the future, and does not sell any excess energy except as it does currently via the New England spot markets. All generating resources are assumed to produce at their existing levels (Coventry is projected using actual production levels from 2012 and holding constant through the planning period), and purchase power contracts are modeled consistent with the terms of the contractual arrangements.

Portfolio 2 ("Effects on WEC of a Vermont Renewable Portfolio Standard (RPS)") assumed Vermont institutes a new Renewable Portfolio Standard with a target of being 80% renewable by 2030. The RPS is modeled with three tiers based on previously debated levels. The tiers WEC assumed for modeling are:

- RPS Existing Renewable (resources online prior to 1/1/2005): 40% of load by 2015
- RPS New Renewable Tier I (resources online between 1/1/2005 and 1/1/2015): 10% of load by 2020
- RPS New Renewable Tier II (resources online after 1/1/2015):
    - 10% of load by 2020
    - 20% of load by 2025
    - 30% of load by 2030

Portfolio 3 ("Coventry Landfill Gas (LFG) Reduction to 50% Output") assumed energy and capacity output from the Coventry LFG plant was reduced by 50% from the Status Quo case. This portfolio scenario represents a case where WEC loses half of its most significant source of power in its mix. This case helps WEC assess its current concentration risk: its reliance on a single large source of power from the Coventry LFG facility. A summary of the WEC portfolios is provided in Table 2-1 inclusive of the assumption of an RPS and the production level of Coventry.

Table 2-1. Summary of WEC Portfolios

| Portfolio | Vermont RPS | Coventry Output Adj. Factor |
|---|---|---|
| Status Quo Case | No | 0% |
| VT RPS - With REC Share | Yes | 0% |
| Coventry Stress Test | No | -50% |

## 2.4. Load Forecast 2014 Overview

The 2014 IRP analyzed WEC's costs for power based on its resource mix and load requirements under various simulations of key variables. The first step in the analysis documents how WEC forecasted load. The analysis then follows up to describe how WEC varied its power resources to meet those load needs. Both the load forecast and overview of the power mix follow.

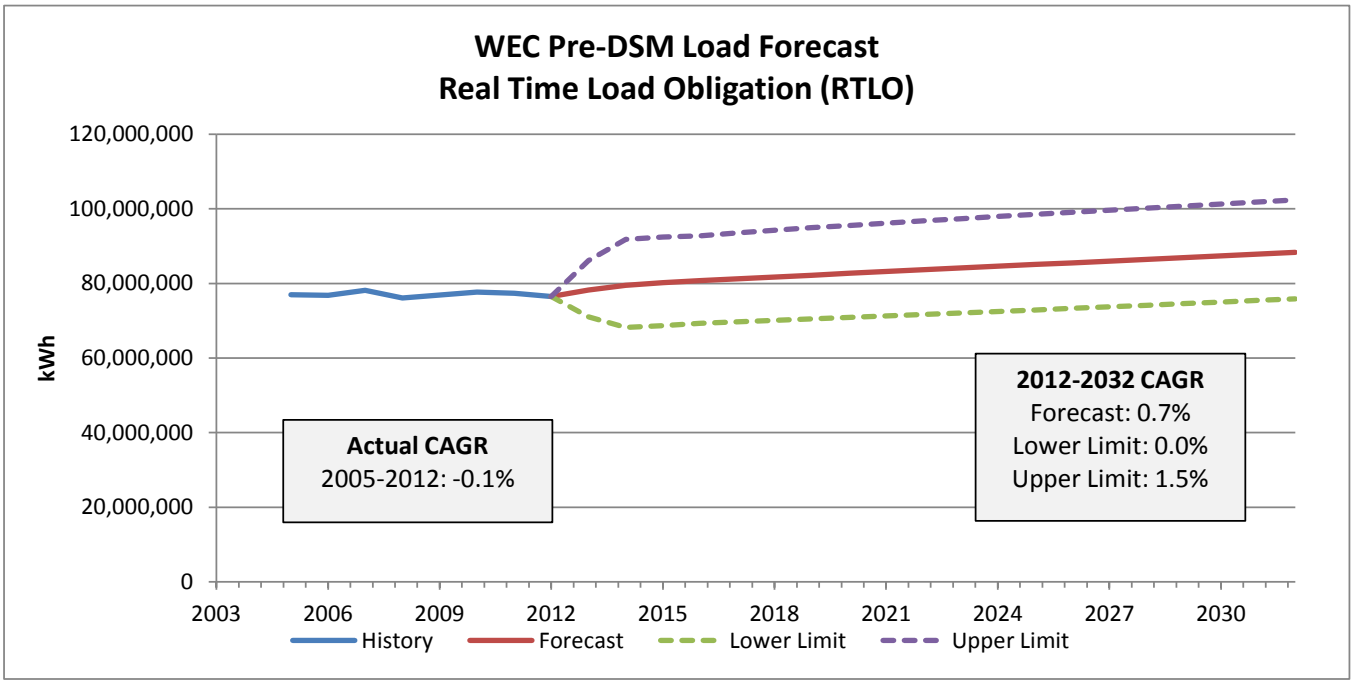
**WEC System Energy—Pre-DSM**

WEC produced a load forecast for its 2014 IRP filing. This effort is described more fully in the last IRP and summarized below. WEC system energy requirements were forecasted using a weighting and blending approach for the first three years of a monthly time series and a monthly econometric approach described in its 2014 IRP.

The results of this prior work are presented below in Figure 2-2. System energy (RTLO) requirements were expected to grow from about 76,500 MWh in 2012, to over 88,300 MWh by 2033, implying a compound annual growth rate (CAGR) approaching 0.7%. The load

forecast estimated with reasonable certainty that the actual CAGR over the planning horizon could vary from 0% to as much as 1.5%.

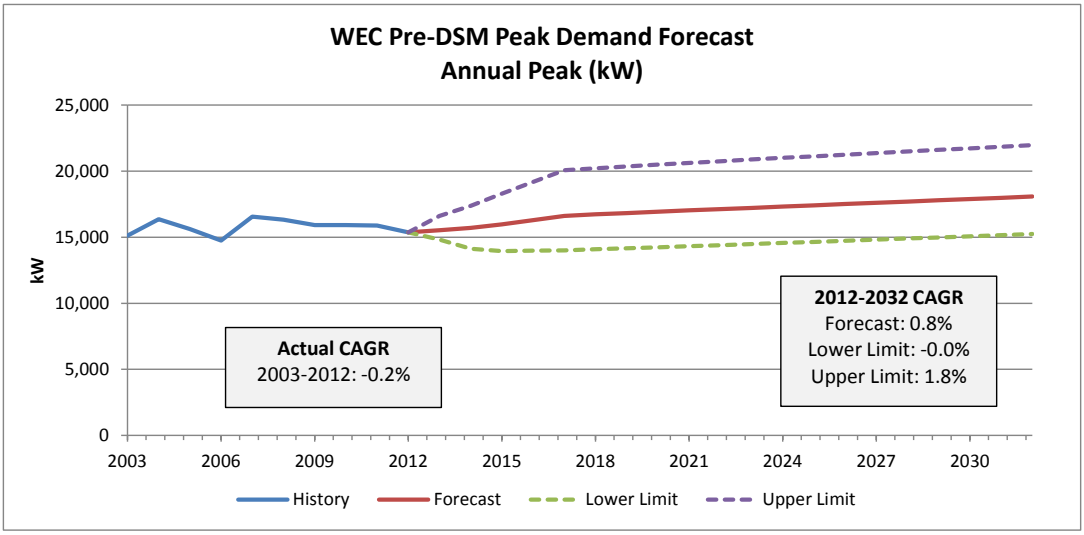
Figure 2-2.WEC Pre-DSM RTLO System Energy Forecast




## WEC System Peak—Pre-DSM

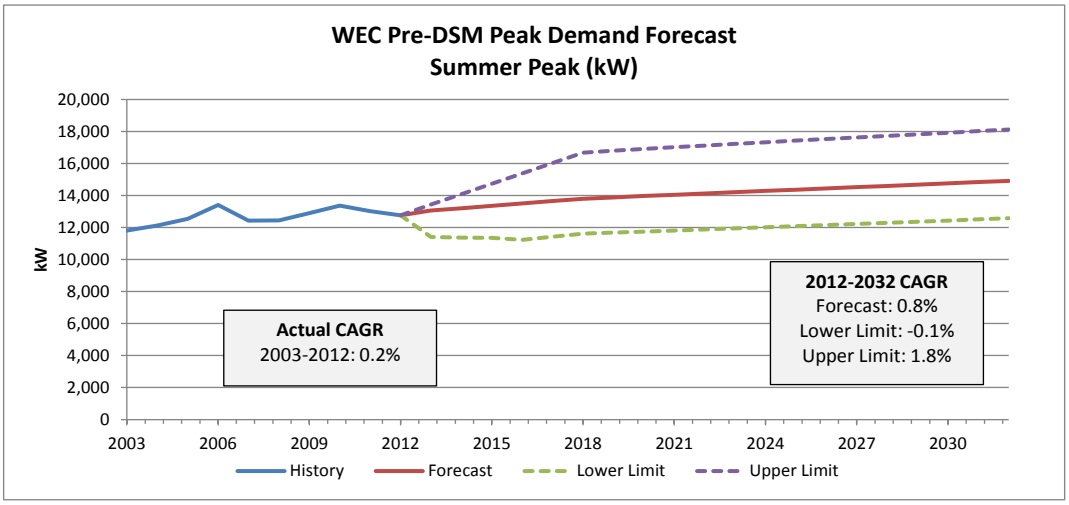
The results of WEC's prior forecasting effort for peak projections are presented in Figure 2-3. WEC's annual system peak demand is expected to continue to occur in the wintertime, maintaining its historical winter-peaking pattern. Based on the prior 2014 forecast work, annual system peak demand was expected to grow from about 15.4 MW in 2012, to about 18.1 MW by 2032, implying a compound annual growth rate (CAGR) approaching 0.8% in that time frame. In this prior study effort, the long-term CAGR was shown to vary from as low as -0.04% in the low case projection to 1.8% in the high case projection, which provides significant confidence that WEC's 2032 system peak could be as low as 15.2 MW to as high as 22.0 MW. The study estimated with reasonable certainty that the actual CAGR could vary from 0% to as much as 1.8%.

Figure 2-3. WEC Pre-DSM Annual System Peak Demand Forecast




Summertime system peak demand [14] was expected to grow from about 12.8 MW in 2012, to about 14.9 MW by 2032, implying a CAGR approaching 0.8% in that time frame. This is shown in Figure 2-4. This long-term CAGR could vary from as low as -0.07% in the low case projection to 1.8% in the high case projection. This means that WEC's 2032 summertime system peak could be as low as 12.6 MW to as high as 18.1 MW.

Figure 2-4. WEC Pre-DSM Summertime System Peak Demand Forecast




[14] Summertime system peak demand is projected by analysis of the historical relationship between WEC summertime peak and annual peak. Since 1996, the ratio of summer peak to annual peak has ranged from 74% to 84%, with one outlier year of 91%. The mean over that time was 80%, with a very slight positive linear trend. The average ratio over the last four years of historical data (2009-2012) was 83%. We project summertime peak demand by multiplying our forecast of annual system peak by the recent four year average ratio of summer to annual peak.

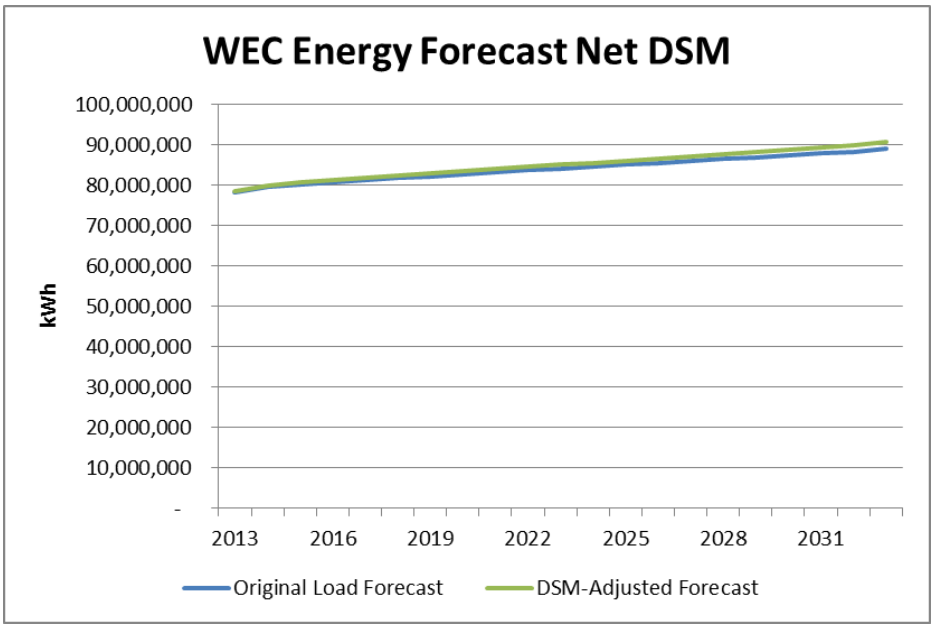
## Demand Side Management Adjustments to Load Forecast

In prior load forecast work, future estimates of savings from energy efficiency assume that the savings will be applied to energy load forecasts that do not include existing energy efficiency. Therefore, the first step in determining the impact future energy efficiency will have on the energy load forecast is to remove any influences that past energy efficiency savings may have on those forecasts. If this adjustment is not made, the energy efficiency estimates may "double count" the historical impact energy efficiency has on the forecast.

## Resulting Post-DSM System Load Forecast

Figure 2-5 shows the resulting post-DSM RTLO forecast from the 2014 IRP. Note that in this case, the DSM-adjusted forecast is actually slightly higher than the original pre-DSM forecast. This is because the amount of historical DSM—about 1.77% of load—added back to the forecast was slightly larger than future annual forecasted DSM savings[15]. This indicates the level of DSM embedded in the pre-DSM forecast was actually slightly greater than the DSM projected for the future.

Figure 2-5. Comparison of original pre-DSM energy forecast and DSM-adjusted forecast




[15] Projections of future DSM savings were provided to WEC by DPS staff in August 2013. WEC's value of the statewide efficiency savings estimates were based on its proportionate share of state load. Therefore, WEC assumes EVT impacts are uniformly delivered throughout the state regardless of utility service territory.

Unlike the energy forecast, the DSM-adjusted peak load forecasts are lower than the original pre-DSM forecasts in later years, reflecting a greater amount of DSM projected for the future as compared to measured historically in recent years. Figures 2-6 and 2-7 show graphically WEC's DSM-adjusted peak load forecast for winter and summer periods, respectively.

Figure 2-6. Comparison of original pre-DSM winter peak load forecast and DSM-adjusted forecast

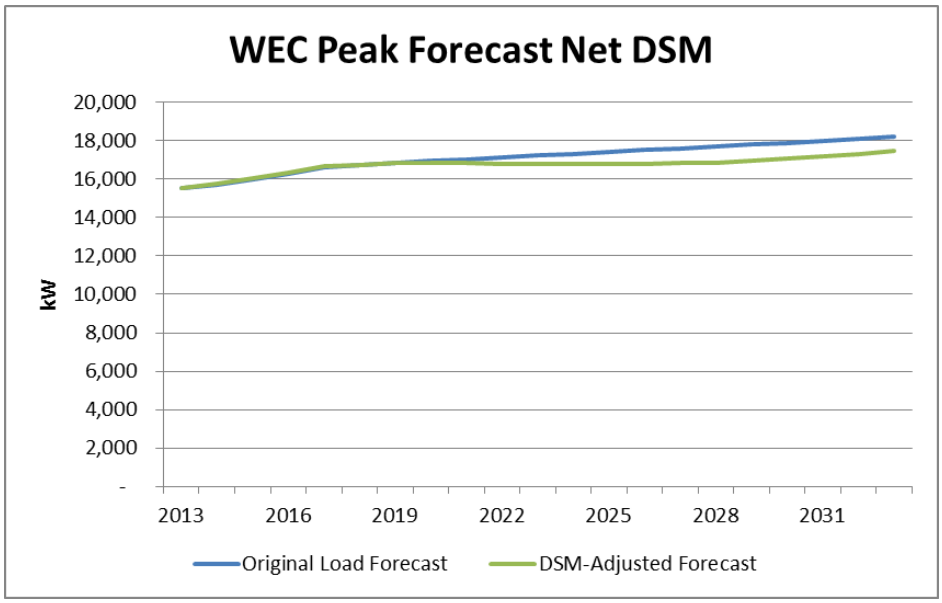
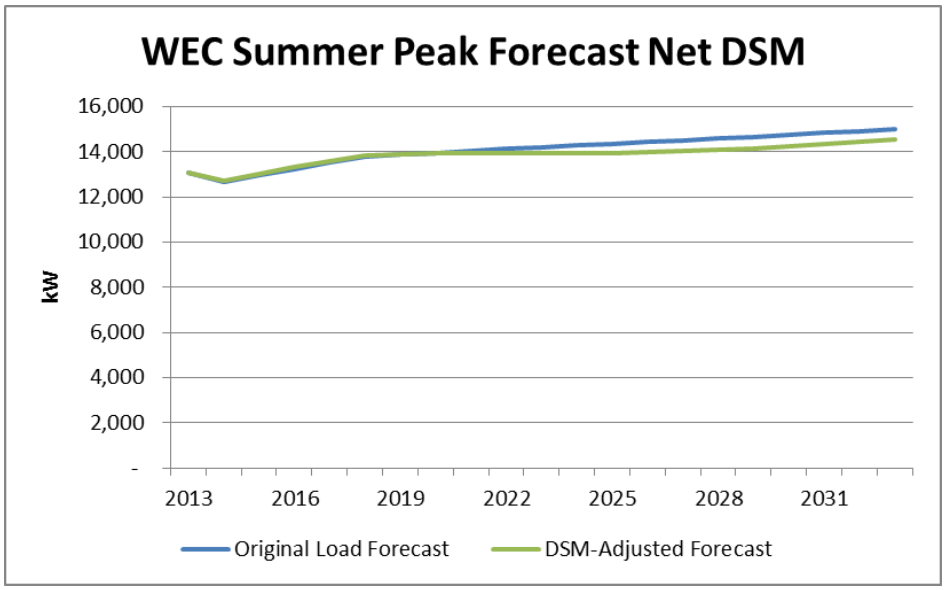



Figure 2-7. Comparison of original pre-DSM summer peak load forecast and DSM-adjusted forecast

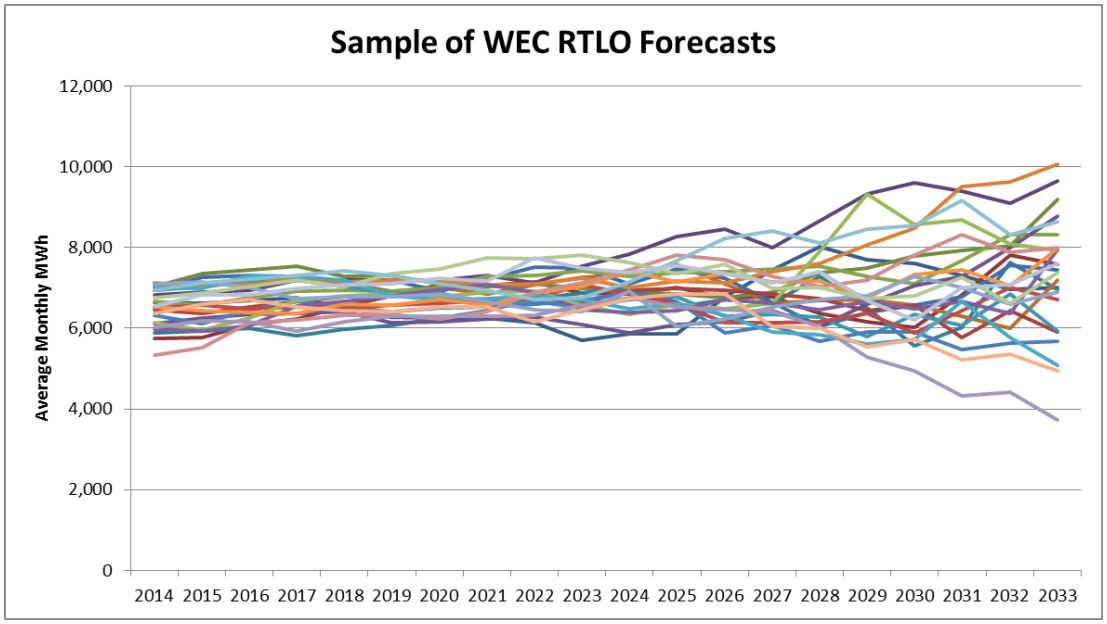


## 2.5. Load Forecast Update 2017

WEC noted the single point forecast generated in 2014 presented one view of a potential future level of load. Since a single point load forecast is less desirable as modeling than using many wide variations of projected load that could likely occur, WEC used a simulation software (Monte Carlo analysis approach) to simulate a wide range of load levels. This allows WEC to account for uncertainty rather than using one projection of load. In order to address impacts from policy, codes, efficiency standards, weather, economic trends, regulatory effects such as Tier II and Tier III and net metering, DSM, and other emerging technologies, WEC believes using a wide range of plausible forecasts is paramount.

In the 2014 analysis, WEC modeled the load forecast using separate normal probability distributions for each year of the forecast. The standard deviations of each of the forecasts were assumed to grow over time to reflect increasing uncertainty. This allowed WEC to model a wide range of load forecasts in the out years of the study period to encompass possible shifts in technology such as the introduction of electric vehicles or large increases in energy efficiency. An example of various projections used in the analysis is shown below in Figure 2-8. Therefore, even if the base case load forecast is not representative of WEC's actual load, by modeling highs and lows of the forecast WEC captures the effect of uncertainty in the analysis.

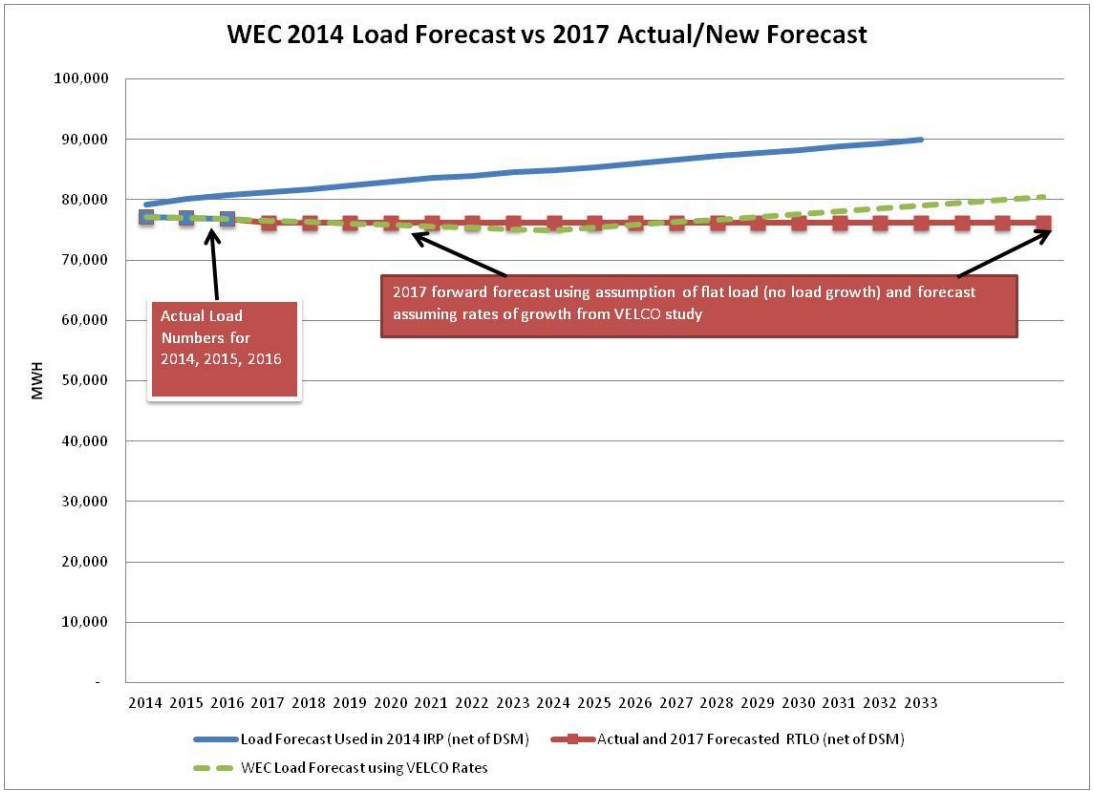
Figure 2-8. Sample Forecast Runs



WEC notes in its current IRP filing that its actual loads from 2014 to 2016, as compared to the single point forecast, are considerably lower than the forecast used in 2014. WEC's loads are lower than the forecasted projections by 2.6%, 3.9%, and 5.0% in the years 2014, 2015, and 2016, respectively. Even though actual loads are lower than projected from the 2014 analysis, the analytic results from the power supply modeling are still relevant. Fundamentally, the results of the Monte Carlo simulation and the impacts of the key variables did not change from the 2014 IRP study. WEC simply gains no new information by rerunning the Monte Carlo study and performing a new load forecast; the key variables identified in the 2014 study remain the same today.

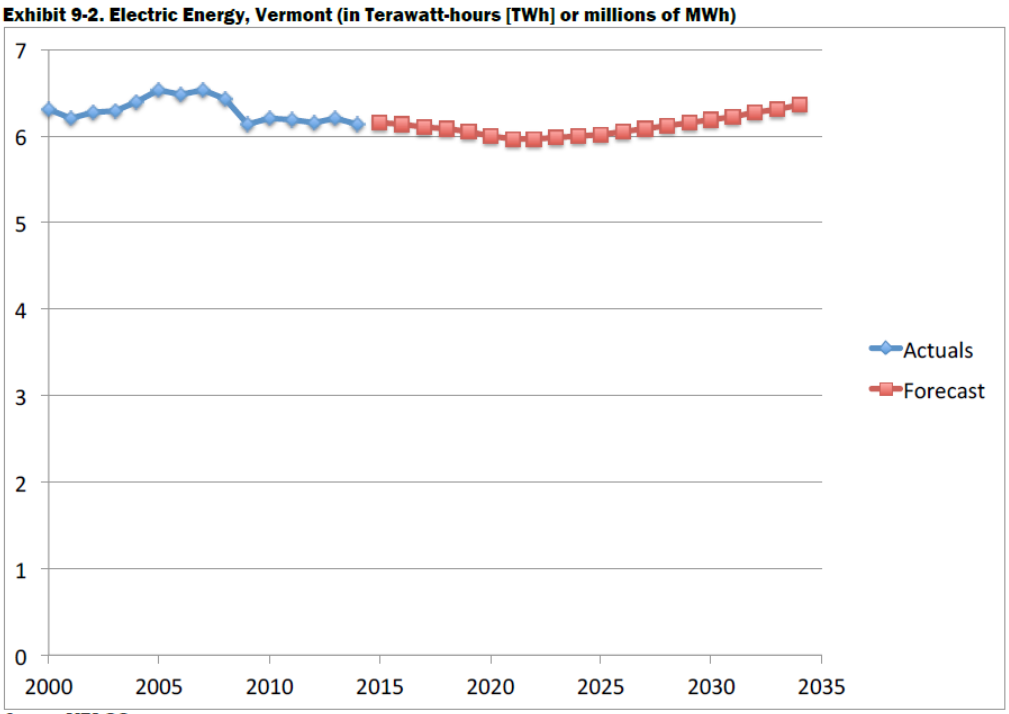
To help frame WEC's current load outlook, WEC used a single point forecast in 2017 and made adjustments looking forward for illustrative purposes. The assumption is WEC will have flat to declining load levels for at least the next five years. This comparison between the 2014 load forecast and WEC's current outlook is summarized graphically in Figure 2-9. This outlook (decline loads) is similar to the projections put forward by VELCO and filed in the 2016 CEP. WEC also used the VELCO rates of decline and growth as a benchmark to its flat growth outlook.

Figure 2-9. Comparison Forecasts



The CEP noted "the VELCO forecast projects an average annual electric use **decline** of 0.3% through 2024, followed by an average increase of 0.6% per year through 2034. The VELCO forecast is a thorough, business as usual snapshot of projected electric load growth."[16] As shown in Figure 2-9 WEC's flat load projection through the planning period is very similar to VELCO's rates of decline and growth that were modeled for the state in aggregate. As a proxy for a robust forecasting effort, WEC believes a flat growth line is appropriate to use in its 2017 IRP. The VELCO forecast work from the 2016 IRP is displayed in Figure 2-10 below.

Figure 2-10. VELCO Forecast




*Source: VELCO*

Regardless of the variance between actual and the 2014 forecast, the rigor of the Monte Carlo simulation in 2014 captured the effect of a scenario with flat to declining loads. Therefore, the outcomes of the simulation capture the effect of a lower load forecast.

WEC will use the lower forecast line to compare and contrast its resources to the new load projection in the next sections. As stated previously, WEC's 2017 load outlook does not change WEC's outlook for new long-term power supply commitments. The biggest impact from a lower load outlook is it pushes farther into the future WEC's need to take back power

[16] 2016 CEP p 184

from VEC for the HQUS PPA. More is discussed on this outlook in the next section.

## 2.6. Overview of Key Inputs to Power Supply Analysis

This section describes the assumptions used for the key variables in the WEC 2014 IRP model. The goal of this analysis was to identify the biggest factors impacting WEC's power costs and to see how costs vary. In WEC's prior IRP, projections for the distribution of key variables affecting power supply costs and revenues were developed along with applicable correlations between them. The potential outcomes for the variables were modeled in the Monte Carlo simulation using predefined distribution shapes for each variable. The outlooks and distributions provide the capability to measure the potential cost and cost variability outcomes associated with each portfolio simulation, using combinations of random and correlated 'draws' for each input variable.

In the Monte Carlo simulation approach, each portfolio was tested under a broad range of conditions by assigning distributions of potential outcomes for the important input or "key driver" variables. The key input variables for this analysis included:

- Natural gas prices;
- Market heat rate;
- ISO-NE Forward Capacity Market (FCM) prices;
- Regional Renewable Energy Credit (REC) prices;
- ISO-NE Regional Network Service (RNS) transmission rate;
- Forecasted WEC load (system energy and peak net requirements); and
- WEC load capacity requirements relative to ISO-NE system peak.

All of the key drivers in the analysis are beyond the direct and immediate control of WEC. Regardless, it is important to understand the impact these variables can have on WEC in terms of cost and operational considerations. Modeling these variables in order to understand their cost impacts assists WEC in its decision-making, affording it the potential to foresee and to mitigate or hedge against undesirable effects.

The key variables in Table 2-2 were modeled in the 2014 IRP work using one distribution for each simulation of the twenty-year forecast period. Details of the forecast shapes for these variables are provided for each variable below. The load forecast, for both peak load and

energy, was simulated using separate normal probability distributions for each year of the forecast. The standard deviation was assumed to grow farther out in time to reflect the greater uncertainty of the load forecast in later years.

Table 2-2. Summary of most key input variable Monte Carlo probability distributions

| | Base or Mean | Minimum | Maximum | Standard Deviation | Probability Distribution |
|---|---|---|---|---|---|
| **Natural Gas[a] ($/MMBTU)** | $5.42 | N/A | N/A | 0.46 | Lognormal |
| **Heat Rate (BTU/kWh)** | 9,490 | N/A | N/A | 985 | Lognormal |
| **FCM Load Charge ($/kW-mo)** | $5.34 | N/A | N/A | $2.67 | Lognormal |
| **FCM Resource Credit ($/kW-mo)** | $5.29 | N/A | N/A | $2.65 | Lognormal |
| **REC MA Class 1 ($/MWh)** | $60.00 | $0.00 | $60.00 | N/A | Triangular |
| **RNS Rate ($/kW-mo)** | $7.11 | N/A | N/A | $1.33 | Lognormal |

a) Used a lognormal of natural gas price in the modeling. The standard deviation of natural gas price is expressed as the log of the variable while the price of natural gas in the table is the average value of the monthly prices.

## 2.7. Analysis of IRP Modeling Results

The intent of the IRP resource modeling process is to provide important information about the costs, features, and risks of various power supply portfolios that WEC could use in the future to meet its system load requirements. The goal is to project cost and cost variance, emissions profiles, and other measures associated with each portfolio, under a broad range of future loads, market prices, economic conditions, and other factors affecting performance, such as market or regulatory changes.

WEC seeks to balance not only cost but a number of subjective evaluation criteria when it looks at its power supply portfolio. These criteria are used qualitative and are as follows:

- **Diversity**: Fuel, resource, duration, and supplier diversity are valuable in the power supply mix to mitigate impacts from a single event on the overall mix of power. This is

very important as New England power markets continue to evolve with a dominance and dependency on natural gas fired power plants (in 2015, 49% of all power in New England was provided by natural gas fired power plants). The marginal MWh of energy needed in New England in 2016 to meet load is normally fired by a natural gas unit, resulting in the hourly market price being set over 75% of the time by a natural gas fired power plant.[17] The result is wholesale power prices are very closely tied to natural gas prices. In times of natural gas shortages due to regional pipeline constraints, power prices tend to be volatile and reliability concerns occur.

- **Risk**: Operational, credit, and reliability risks can all be used to assess and describe a power mix. By owning generation, operational risk is built into a power portfolio in which mechanical, fuel, and operation risk are added to the list of issues a utility must manage. Credit risk is equally important, as the market has seen a number of bankruptcies making power contracts less than certain long-term. Reliability considerations can apply to owned power plants as well as power contracts in terms of delivery and adherence to contract terms. All of these dimensions must be taken into account when planning and examining a power portfolio.

- **Uncertainty**: Assessing the uncertainty of a power mix can be a valuable tool in understanding how likely changes are to power costs and to measure volatility. Measuring uncertainty can lead to varying resource decisions given prior or upcoming commitments.

- **Environmental Impacts**: Assessing the environmental impacts of a power mix is essential to WEC, as one of WEC's core missions is to minimize the environmental impacts of electric generation and our operations.

## 2.8. Key Influences on Net Portfolio Costs by Portfolio

As provided in the 2014 IRP, the affect of key variables on the total net portfolio cost was summarized through the use of a Tornado Chart. The Tornado Chart for the Status Quo portfolio is shown below (see Figure 2-11). Each bar is generated by moving the value of one variable to the 90$^{th}$ and 10$^{th}$ percentile values in its probability distribution, while leaving the values of the other variables at their median values. The bars are then stacked with the variable

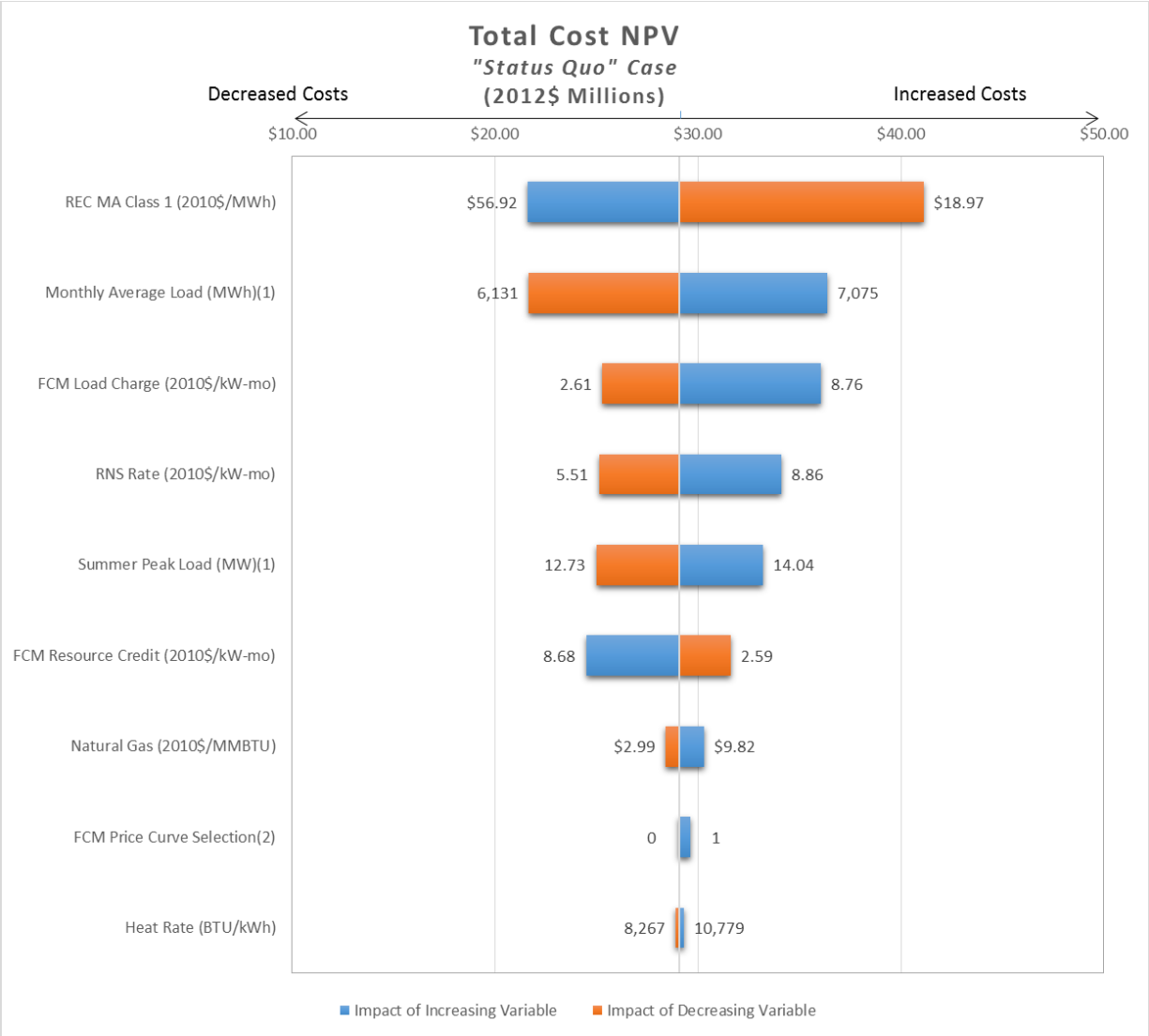
[17] ISO-NE, https://www.iso-ne.com/about/key-stats/markets

causing the largest variation on top and the smallest variation at the bottom.

The color of the bar indicates whether the change reflects an increase or decrease to the variable in question. As an example, the REC price variable has the orange bar to the right and the blue bar to the left, indicating total costs increase as REC prices decrease and vice versa, whereas the load variables have the orange bars to the left and the blue bars to the right, indicating total costs increase as load increases and vice versa. The data labels next to each side of the bar show the $90^{th}$ and $10^{th}$ percentile values of each variable in the analysis.

For the Status Quo case, the most important variable was REC price, because WEC's resource portfolio is composed entirely of renewable resources, the largest of which, Coventry LFG, generates RECs and REC revenues.

Figure 2-11. Tornado diagram for Status Quo case showing variation in the NPV of total portfolio costs.




(1) Load variables have separate probability distributions for each individual year. For purposes of making the Tornado diagram, results reflect a change to the entire twenty-year forecast to better compare to the other variables. The input and data labels reflect the probability distributions from the first year.

(2) The price curve labeled "0" is the curve from the original LCA forecast and was used as the base case. The curve labeled "1" increases the FCM price to the scarcity price in 2018.

Table 2-3 summarizes the variables with the greatest impact on total costs for each portfolio taken from the Tornado Charts for each case. The Vermont RPS portfolio has the same most influential variables as the Status Quo case, but with the positions reversed. The influence of Massachusetts REC prices is lower in this case, as there is a reduction in potential REC sales. The Coventry Stress Test case is much more influenced by natural gas prices

because WEC is predicted to make far more energy market purchases than in other cases. All three cases are heavily influenced by WEC's projected energy demand.

Table 2-3. Summary of most influential variables for each portfolio and impact to variation in the NPV of total costs.[18]

| Portfolio | Most Influential Variable | Swing (Millions of 2012$) | Second Most Influential Variable | Swing (Millions of 2012$) |
|---|---|---|---|---|
| **Status Quo** | MA REC Class 1 Prices | $19.5 | Average load in MWh | $14.7 |
| **Vermont RPS** | Average load in MWh | $16.7 | MA REC Class 1 Prices | $12.4 |
| **Coventry LFG Stress Test** | Natural Gas Prices | $20.5 | Average load in MWh | $14.1 |

## 2.9. Net Portfolio Costs by Portfolio

Also from the 2014 IRP, Table 2-4 provides a summary of the total NPV of costs for each portfolio (in millions of 2012 dollars) assuming each key variable is at its median value. The Status Quo case has the lowest total costs, as this case has the highest amount of REC sales to offset energy and other market costs. The Vermont RPS case assumes some RECs must be retired to meet the new renewable requirements for the state, lowering REC sales and increasing energy and other market costs, but leaving capacity and RNS transmission costs the same as the Status Quo case. The Coventry LFG Stress Test increases total energy and capacity costs as the reduction in Coventry output makes WEC more reliant on market purchases and decreases REC sales dramatically.

Table 2-4. NPV of the costs of each modeled WEC portfolio assuming each key variable is at its median value. (2012$ millions)

| Portfolio | Net FCM & Capacity Costs | ISO RNS | Net Energy and Other Market | TOTAL COST |
|---|---|---|---|---|
| **Status Quo** | $7 | $19 | $4 | $29 |
| **Vermont RPS** | $7 | $19 | $12 | $37 |
| **Coventry LFG Stress Test** | $9 | $19 | $25 | $53 |

[18] The swing is equivalent to the width of the bars in the Tornado Charts.

The results of each Monte Carlo draw were also saved, and these results provide insight into the range of possible outcomes. Figure 2-12 shows a summary histogram of the NPV of the total costs under the Status Quo case. The mean of the distribution is $31.6 million and the distribution overall has a slight positive skew toward higher costs.

Figure 2-12. Histogram of the NPV of the total costs of the Status Quo case after 1000 Monte Carlo draws (2012$ millions).

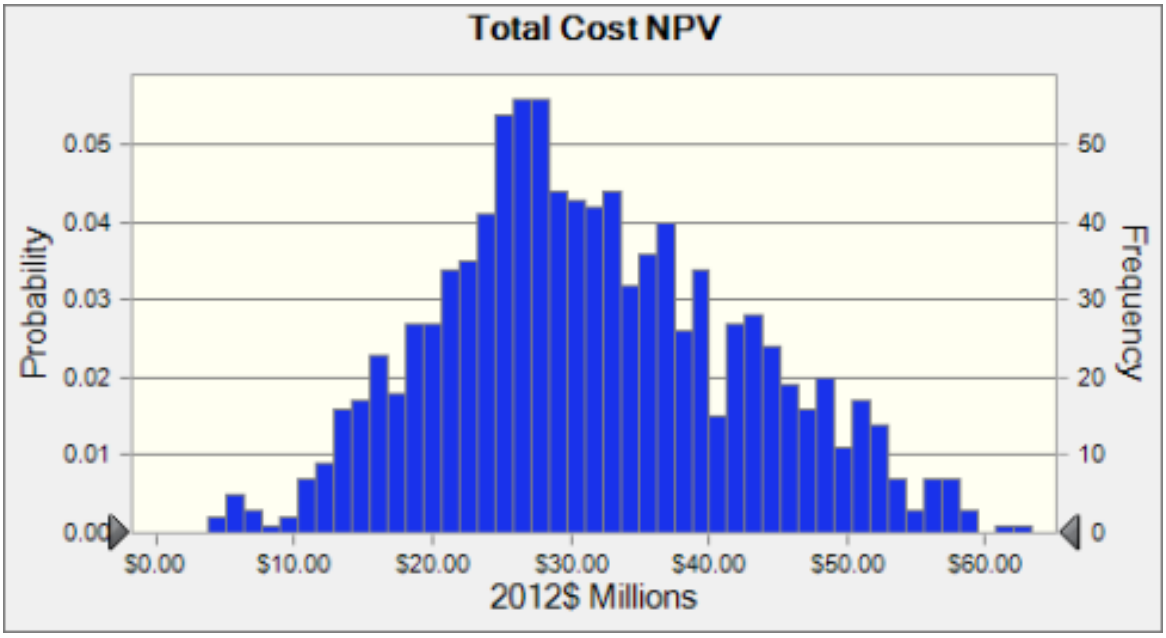



Table 2-5 below summarizes key statistics for the Monte Carlo draws of each portfolio. Please note WEC included in Table 2-5 societal cost values in addition to other cost data and summary statistics. While additional information about societal costs is found later in the IRP (Section 2.10 addresses environmental externalities) WEC included the data in Table 2-5 for comparative purposes to the other cost and volatility metrics. This is to help the reader more readily compare and contrast portfolio impacts by including environmental impacts alongside other cost dollar statistics.

Table 2-5. Summary statistics regarding the distribution of the NPV of total costs (2012$ millions) for each portfolio.

| Portfolio | Base Case NPV | Societal Cost Pre REC Sales | Societal Cost Post REC Sales | Mean NPV | Std. Dev. | Min. | Max. | Range | Mean Std. Error | Coefficient of Variation |
|---|---|---|---|---|---|---|---|---|---|---|
| **Status Quo** | $29.63 | $30.23 | $46.43 | $31.6 | $11.4 | $(5.7) | $71.3 | $77.1 | $0.36 | 0.3592 |
| **Vermont RPS** | $37.29 | $37.89 | $49.79 | $39.1 | $10.6 | $6.9 | $78.0 | $71.1 | $0.34 | 0.2715 |
| **Coventry LFG Stress Test** | $52.67 | $56.97 | $66.27 | $56.6 | $13.4 | $30.0 | $154.3 | $124.3 | $0.42 | 0.2364 |

As Table 2-5 shows, the Vermont RPS case has lower variability—as measured by the standard deviation, range, and coefficient of variation—compared to the Status Quo case. This is due to the reduced exposure to REC prices in this case. The Coventry Stress Test portfolio has a larger range and standard deviation compared to the Status Quo case, but the lower coefficient of variation indicates the amount of variability is lower compared to the mean of the distribution. The mean is much higher in the Coventry Stress Test due to the exposure to market purchases and the reduction in REC revenues.

## 2.10. Effects of Environmental Externalities

Table 2-6 below provides results of the emissions modeling for each portfolio both before and after REC sales are taken into consideration. WEC used emissions based on the NEPOOL GIS residual mix for the underlying energy that is retained in the power mix post REC sale. The Status Quo and Vermont RPS cases are the same before REC sales are taken into consideration, as the generation resources are the same.

However, the Status Quo portfolio has higher post REC emissions and CO2 costs because there are a larger amount of REC sales in this case. The Coventry Stress Test case has much higher emissions before REC sales compared to the other portfolios because the reduced Coventry generation is replaced by market purchases with an emissions profile reflecting the NEPOOL GIS Residual Mix. In contrast, the Coventry Stress Test portfolio has a much lower increase in emissions from REC sales as it has many fewer RECs available for sale from

Coventry.

Each resource decision relative to entering contracts, building generation, selling, and/or buying RECs comes with both a monetary cost as well as an environmental cost. In Table 2-5 the "Base Case NPV" costs for each portfolio represent the total dollar impact on WEC's rates from its resource decisions, but this number is calculated without regard to environmental impacts. This metric is referred to as a measurement of rate payer costs. The next two columns, "Societal Cost Pre REC Sales" and "Societal Cost Post REC Sales" represent the cost in terms of rates as well as the cost to the environment of WEC's resource decisions. Both of these metrics include both rate payer and societal costs. By measuring this way, WEC can compare and contrast the impacts of various portfolios. Furthermore, by measuring the portfolio in terms of pre and post REC sales, WEC can measure the impacts of its decision to sell RECs. WEC uses the societal cost impacts to measure and report on the environmental cost implications from its power portfolio decisions.

While the revenues received from selling RECs help reduce WEC's rate payer cost, it has the counter effect of increasing its overall societal cost of the power mix. This is clearly displayed in Table 2-5 and further quantified in Table 2-6.

WEC must weigh the value in its power supply decision-making of both low cost power as well as low societal costs. The decision to buy and sell RECs is driven by the impact on WEC's rates as well as the environment. WEC decision-makers put a high priority on keeping rates affordable. WEC decision-makers also put significant emphasis on having low environmental impact. In review of the rate payer cost and societal cost metrics, WEC plans to lower its societal cost by buying back RECs and thereby greening back up the power mix. WEC plans to sell its high value Class 1 market RECs (which helps to keep rates low) but then green back up the mix by buying sufficient lower priced Class 2 market RECs. This will have the effect of lowering WEC's societal costs while preserving the benefits of lower rate payer costs. This action is described in Section 6 in the Action Plan.

Table 2-6. Emissions modeling results summary for each portfolio. CO2 costs are in millions of 2012$.

| | **Pre REC Sale** | | | | **Post REC Sale** | | | |
|---|---|---|---|---|---|---|---|---|
| **Portfolio** | $SO_2$ (tons) | $NO_x$ (tons) | $CO_2$ (tons) | $CO_2$ (NPV M$) | $SO_2$ (tons) | $NO_x$ (tons) | $CO_2$ (tons) | $CO_2$ (NPV M$) |
| **Status Quo** | 35 | 19 | 13,452 | $0.6 | 1,027 | 537 | 386,459 | $16.8 |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| **Vermont RPS** | 35 | 19 | 13,452 | $0.6 | 693 | 362 | 260,717 | $12.5 |
| **Coventry Stress Test** | 285 | 149 | 107,155 | $4.3 | 850 | 444 | 319,703 | $13.6 |

## 2.11. Conclusions

The 2014 IRP analysis documented the impact of projected variations in operating, market, and regulatory conditions on the costs and cost variability of each resource portfolio. This allowed WEC to project expected present value costs for each portfolio, as well as the distribution of possible cost outcomes around an expected value.

WEC uses portfolio review and the simulation of its long-term power supply commitments to help guide its decision making. The process allows WEC to identify key risk drivers, which allows WEC to create plans to reduce these risks while also reducing cost and volatility. Some of these risks are presented by major market influences and events that are well beyond WEC's control. With such uncertainty in mind, WEC seeks to minimize to the extent possible negative outcomes to its membership, such as impairment of WEC financial performance or increased emissions of its power supply mix.

The biggest risk impacting WEC's financials identified in the 2014 analysis are identified in the tornado chart in Figure 2-11. Changes to the price of RECs, load, FCM, and ISO-NE Transmission charges were identified as the largest factors that impact variations in WEC's costs. These key variables continue to be relevant today.

In fact, in 2016 WEC filed a 6.52% rate increase with the largest driver being due to a decline in the price of RECs (RECs accounted for just over half of the rate increase, or 3.04%), while power costs due to transmission and FCM accounted for another 1.56%. The remainder, or 1.92%, is due to operational costs (service of wires, poles and substations, labor, benefits, and other financial costs). As predicted in the 2014 analysis, a drop in REC prices triggered significant cost pressure to WEC. This occurred as REC prices declined in the last year from mid $40s to low $20s. At the same time the REC market dropped off, the cost of transmission and capacity also increased. These three items, in addition to flat sales due to net metering, are 74% of the 2017 rate request.

## REC Risk

WEC uses a portfolio approach to selling its RECs, which emphasizes transaction and timing diversity. In its simplest form, WECs enters several forward trades at various points in time with several counterparties. WEC seeks to capture favorable market prices that average out the ups and downs in the market, and looks to have reasonable credit risk among counterparties. WEC's fundamental goal is to maximize revenue while minimizing risk and price uncertainty. To carry out its goals, the Co-op uses a pragmatic approach and one that doesn't create an undue burden and administrative work to track and manage contracts.

There is no prescriptive number of trades, but WEC also knows the more contracts it has, the more administrative work is needed to execute, track, and process each trade. Hence, it seeks to limit the number of trades to a reasonable number in a given year (generally less than 10). WEC also leaves roughly 10 to 15 percent of its position uncommitted until the end of the year to allow for production variability at Coventry. This also helps to contribute to budget certainty for the year. WEC looks out several years into the future and makes use of forward sales at various points in time. However, the closer to the year of production, the more emphasis is put on securing sales for that year.

WEC's portfolio approach helped to reduce the impacts of the significant fall in REC prices in 2016. While it did see impacts to rates, as WEC needed to file for a rate increase, it would have been far worse had the Co-op not sold RECs prior to the crash in the 2016 REC market.

Prior to 2016, the markets had been in an inverted state for several years, with future years selling lower than periods closer to a year of production. This decreased the desire to enter sales many years into the future. If, however, WEC waits and sells everything close to the year of production, this leaves uncertainty and risk that the markets could fall. WEC seeks to balance these competing interests through its REC sales approach.

## Capacity and Transmission Risk

WEC is reviewing its cost and rate structure to see if different rate design approaches may lessen the impacts of falling RECs and increased power costs that are beyond WEC's control (such as the price of capacity in the FCM market and cost of transmission). More is discussed on rate design in Section 5 and Section 6.

In order to control capacity and transmission costs, WEC seeks to explore utility scaled

battery storage. Use of large battery storage can help reduce WEC's load at the time of the ISO-NE peak. FCM charges are assessed to load based on WEC's share of load at the single hour of the year that the region uses the most power. To the extent WEC can predict the peak and deploy battery at the time the region peaks, the following year capacity costs will be lower.

Batteries can also help to reduce transmission costs. Transmission is assessed based on monthly peaks. To the extent batteries can be deployed at the time of monthly peaks, transmission costs can be lowered. WEC will perform analysis of utility scale batteries in the upcoming year.

**Methods Used to Evaluate and Mitigate Key Power Cost Risks**

WEC's existing power portfolio is reasonably stable and generally known over the next 20 years due to existing long-term contractual commitments and generation resources. Through the IRP analysis WEC has identified that it can minimize costs to its members if it operates under the Status Quo case conditions.

WEC is also able to assess the variability of the cost of its power mix by running various simulations of the key variables. While the Status Quo case and Vermont RPS portfolios are more stable, a sustained loss of half of WEC's Coventry generation will not only increase WEC power supply costs, but create substantial variance in costs with potential accompanying retail rate pressure. A decline in REC prices also puts tremendous pressure on WEC's costs and influences WEC's need to increase rates.

It should be noted that WEC's Status Quo case has a very low emission profile and resulting societal and emissions cost before considering its REC sale practices, as compared to the other cases. After WEC sells RECs for wind and Coventry, then WEC's emissions profile is higher in the Status Quo case simply due to the sale of RECs. This tradeoff, between lowering cost to members and keeping rates low versus incurring a higher emissions profile, can be changed. In fact, WEC made the decision in 2014 to buy back low cost RECs to green back up its power supply mix after high value RECs are sold.

Assessing the Status Quo portfolio based on diversity criteria, WEC has a large single resource risk in Coventry. Coventry provides two thirds of WEC's energy needs in most years through the 20 year planning horizon. As a result, WEC has risk in its portfolio and some degree of uncertainty that it should consider ways to mitigate and manage.

WEC has mitigated a significant portion of loss risk from Coventry through the terms

of the sleeve agreement to VEC. As part of the assignment to VEC for WEC's 4,000 kW of HQUS PPA, the arrangement includes a provision that allows for a call back of power of the HQUS PPA contract if WEC has an unplanned outage lasting more than 30 days from any of its existing resources. Therefore, in the event of a significant loss of Coventry in the near term, WEC can use the HQ US PPA as a backstop to cover roughly half of the loss of generating station. This 4,000 kW option is of considerable value to WEC and its members to diversify WEC's portfolio in the event of a loss of Coventry or other existing resources in its mix.

WEC also carries business income loss insurance for the Coventry plant. In the event of loss of revenue due to a catastrophic event, such as fire, tornado, flood, etc., this policy will respond and provide WEC basic coverage due to loss of income from the plant. This is a further protection to WEC and helps to mitigate its reliance on Coventry in the power portfolio.

The other portion of WEC's power portfolio is comprised of various contracts (including large hydro, small hydro, biomass, and wind) and WEC's Wrightsville hydro generation. This portion of the portfolio provides a diverse mix of contracts and resources that represent varying suppliers, different fuel types, and varying durations. This portion of the mix provides reasonable diversity and lowers risk and uncertainty to WEC.

The underlying sources of WEC committed power are all stably priced renewable power sources leaving WEC insulated from volatility in the natural gas markets, which dominate the regional mix of resources in the New England markets today and essentially set the price of power at the wholesale level. Therefore, WEC's portfolio is well hedged against and insulated from short and long-term price swings in the fossil fuel markets. In fact, in the Status Quo portfolio, natural gas was one of the least significant variables as measured in the tornado chart in Figure 2-11.

For the Status Quo case, the most significant variables WEC needs to focus on are REC availability and price, load, FCM, regional transmission costs, and peak. These are key drivers to power and transmission costs to WEC and produce the most chance to increase or decrease WEC's power costs. In fact, natural gas and heat rates were insignificant in the base case to WEC's power related costs.

However, in the Coventry Stress Test case, natural gas becomes the top key variable. In this case, WEC has significant market exposure due to the loss of Coventry. As a result, natural gas costs and increased emissions become key risks if WEC were to face a large portion of its load being unhedged. In this situation, WEC would be exposed to the underlying market prices at the wholesale level.

Unlike the VT RPS case, which is largely out of WEC's control, the "Coventry Stress Test" case identifies risks that WEC should focus on to reduce its risk to sudden exposure to the natural gas dominated energy markets in New England. More on these issues can be found in Section 6 discussing Action Plans.

# 3. Committed Supply Resources & Projected Requirements

## 3.1. Overview of Existing Resources

WEC's current committed power supply mix is summarized in Table 3-1. Following the table is a narrative description of each resource. WEC's current resource mix provides it with long-term stability as well as the ability to react to RPS markets. WEC's power portfolio also meets the State's renewability goals, as all resources are based on renewable sources of power. Another attribute is that WEC's largest sources of power are located close to WEC's load, which helps to alleviate price separation between load and generation.

Table 3-1. WEC Committed Supply Asset Inventory

| Name | Nameplate (kW) | Fuel Source | Start Date | End Date |
|---|---|---|---|---|
| **Coventry Landfill Gas** | 8,000 | Landfill Gas | 7/1/2005 | 2038 |
| **New York Power Authority** | 1,570 | Hydro | NA | Life of Contract |
| **Hydro Quebec VJO Sch B** | 2,589 | Hydro | 11/1/1995 | 10/31/2015 |
| **VEPPI** | 410 | Hydro | 1984 | 2020 |
| **Ryegate (WEC's Allocation)** | 273 | Wood | 2012 | 2021 |
| **GMP Rate W** | 138 | System | NA | 7/31/2016 |
| **Wrightsville Hydro** | 1,000 | Hydro | 9/1/1985 | Life of Unit |
| **Sheffield Wind** | 4,000 | Wind | 10/19/2011 | 10/19/2031 |
| **Hydro Quebec US PPA** | 4,000 | Hydro | 11/1/2016 | 10/31/2038 |

**Coventry Landfill**

The Coventry landfill generating facility is located in Coventry, Vermont at the New England Waste Services of Vermont Landfill (or NEWSVT). The facility currently has a maximum generating capability of 8,000 kW, though average output has been between 5,500 kW and 6,500 kW over the past few years. Production is driven by the amount of methane gas produced at the landfill and based on the gas collection system's ability to capture, extract, and

process the gas. The facility started with three 1,600 kW engines in 2005, and WEC has since expanded the plant by adding two additional 1,600 kW engines. The generators burn the processed landfill gas that is collected from gas wells at the Coventry landfill.

In 2016, WEC added a new gas scrubbing Siloxane Removal System (SRS), which removes siloxanes from the gas. Siloxane acts as a corrosive when burned in the engines; removing siloxanes reduces the concentration of compounds in the landfill gas. The buildup of siloxane compounds within the engines causes destructive detonation and inefficient operation of the generators, causing additional maintenance and engine downtime. Removing the siloxane compounds will improve engine availability and increase electricity production.

The other major factor impacting production at the Coventry plant is the volume of gas produced and extracted from the landfill. Over the past two years the volume of gas extracted has increased. This was due in part to concerted efforts to increase the level of gas extraction. WEC is working collaboratively with NEWSVT management, staff, and technicians trained in maximizing gas extraction. Work was done to rebalance gas wells for optimal methane to oxygen content, and WEC invested in pumps to dewater wells. It continues to monitor the progress made to date and work continues to optimize gas extraction.

It is important to remember that the Coventry landfill is in a state of constant flux. NEWSVT continues to accept waste and plan for the operation and management of the various physical areas (known as phases and cells) in an ongoing and active process. Many factors can affect the wells and gas volumes, including not only the content of the waste stream but other external issues. Damage from heavy equipment working in and around the landfill, freeze/thaw events which can lead to cracked lines, water in the wells, failed pumps, operational work and redesign of various cells/phases, and compliance with state permits are a few noteworthy factors that impact gas collection.

The NEWSVT landfill has been in continuous operation since 1993. Previous gas generation studies included waste filling data from NEWSVT records through 2013 and a projected future filling rate of 350,000 tons per year. The waste filling records show a total of approximately 425,600 tons, 444,700 tons and 492,400 tons disposed at the NEWSVT landfill in 2014, 2015, and 2016, respectively. Total disposal reached an annual historic high last year.

We have been advised by NEWSVT that they project a future waste disposal rate of 475,000 tons per year, although their permit allows up to 600,000 tons per year. The Phase IV landfill is expected to continue receiving wastes through 2022 when it will reach capacity.

Filling will then commence in the newly permitted Phase VI landfill, with a projected 22-year useful life at 475,000 tons per year filling rate, reaching its capacity by 2044. The previously permitted Phase V landfill would begin receiving wastes in 2045 and reach its capacity by 2051.

Based on the filling history figures, as of the end of 2016 the landfill has 6.87 million tons of waste in place. The currently permitted landfill limits (Phases I – VI) have a total capacity for 23.4 million tons, or approximately another 16.5 million tons of future filling capacity. At the estimated rate of future filling of around 475,000 tons per year, the current landfill has sufficient capacity to continue operating through 2050 and into 2051.

Casella filed permits for a new phase of the landfill (Phase VI). Based on planned gas extraction from the existing phases (I-V) and from the proposed Phase VI, WEC believes the gas production will increase to a level that allows all five engines to run at maximum output. However, Act 148, the state's universal recycling law, calls for food scraps to be diverted from the landfill, with all food waste targeted to end by 2020. Enforcement of this law at the homeowner and small scale producer level is impractical, and therefore the Department of Environmental Conservation (DEC) believes roughly 40% of the state's food scraps will remain in the waste stream; hence DEC experts believe some level of organics will continue.

WEC periodically hires consultants to perform long-term gas flow modeling and a consultant is currently working on an updated model. WEC expects to finish a report in 2017. This report will be helpful and the outlook is based on waste content, operation considerations, and other factors, such as impacts from Act 148.

**New York Power Authority (NYPA)**

The New York Power Authority provides inexpensive federal preference hydroelectric power to the utilities in Vermont under two contracts. The first contract is a 31 kW entitlement to the Robert Moses Project (a.k.a. "St. Lawrence") located in Massena, New York. The second contract, known as the "Niagara Contract," is for a 1,539 kW entitlement to the Niagara Project located at Niagara Falls, New York. The contract for St. Lawrence has been extended through April 30, 2017. The Niagara Contract has been extended through September 1, 2025.

**Hydro-Quebec/Vermont Joint Owners' (HQ VJO) Contract**

WEC's entitlement in the HQ/VJO contract was 2,589 kW, provided under Schedule B. This contract expired on November 1, 2015. The shortfall created from this contract is in part replaced by existing resources and the new Hydro Quebec (HQ) US PPA. See details below

for the HQUS PPA.

**Vermont Electric Power Producers, Inc. (VEPPI)**

WEC receives power from numerous hydro plants in Vermont that are independent power projects (IPPs) through the state-mandated Rule 4.100 program administered by the appointed purchasing agent, VEPPI. In 2016 there were eighteen IPP hydro generation resources in Vermont. VEPPI assigns power to all Vermont utilities based on a pro-rata share of the previous year's electric sales, which is updated annually. WEC's current share of the resources is approximately 250 kW or 1.3%. Contracts between VEPPI and the independent power producers began to terminate in 2008 and all the current hydro contracts will expire by the end of 2020.

WEC receives output from the largest IPP resource (the Ryegate wood-fired facility) and is allocated power based on load ratio share. WEC's portion of Ryegate is currently 1.3%, which provides 273 kW of base load power. A new contract with Ryegate was implemented through Docket 7782 in which costs and benefits are distributed to Vermont utilities based on a price set by the Vermont Public Service Board. In 2011, Act 471 mandated the establishment of a standard-offer price for certain baseload renewable power sources. In an Order dated October 29, 2012, the PSB established a standard-offer price schedule for baseload renewable power (Ryegate biomass facility) that is represented by a levelized price of $0.10 per kWh and that included a fuel pass-through mechanism, by which the price will be adjusted to reflect changes in Ryegate's fuel costs. The new contract began November 1, 2012 at the termination of its Rule 4.100 VPX contract. The new contract for Ryegate is in effect for ten years or from 11/2012 through 10/2021.

**GMP System Power—Rate W**

WEC historically had been provided a small portion of power to serve its Jones Brook circuit from GMP, purchased under GMP's FERC-administered Wholesale Rate W tariff. The billing is determined monthly and was based on WEC load metered at GMP's Berlin substation. In August 2016, WEC successfully converted this load from a wholesale energy supply rate (WEC was paying a premium to serve the load) to a transmission rate under GMP's Open Access Transmission Tariff. The result of this change in tariff is savings to the Coop.

**Wrightsville Hydro**

WEC's Wrightsville Hydro unit is a hydroelectric facility with limited ponding capability, and is located below the Wrightsville Dam on the North Branch of the Winooski River in Montpelier, Vermont. WEC owns and operates the facility and utilizes all of its

output. The nameplate rating of the facility is 1,000 kW, but energy production is determined by water flows. Wrightsville began creating power in September 1985, and continues to be a valuable source of economic hydropower for WEC.

In March 2016, WEC successfully converted the hydro unit's status at the ISO-NE from a generator to a load reducer. As a load reducer, the production from Wrightsville goes directly toward lowering WEC's load with the ISO-NE. The effect is the unit is no longer treated as a generator in settlement by the ISO-NE.

This change saves WEC in ancillary market costs, capacity costs, reserves, and many other expenses assessed to load by the ISO-NE. WEC continues to record generation monthly for internal tracking and adjusts load internally as if the generator were not a load reducer. This allows it to measure and track WEC's total member load for planning purposes.

The Wrightsville Hydro facility was issued a 40-year license by the Federal Energy Regulatory Commission (FERC) on November 23, 1982 (FERC No. 5124, also known as North Branch No. 3 Hydroelectric Project). At the time of the license, the project was owned by the Montpelier Hydroelectric Company; it was later transferred to the Washington Electric Cooperative, Inc. (WEC) on June 30, 1983. The current license expires on October 31, 2022. WEC must file its Notice of Intent (NOI) and Pre-Application Document (PAD) between May 1, 2017 (5.5 years prior to license expiration) and October 31, 2017 (5 years prior to license expiration).

WEC is exploring and researching the requirements and options to renew the license. A preliminary meeting was held with Vermont Agency of Natural Resources (VANR) in 2016. WEC is discussing plans and FERC requirements with technical experts to help guide WEC through the process. Based on initial discussions and information from FERC and VANR, the license renewal process is complex.

Following an initial meeting with VANR in December 2016, which was held to identify potential studies required to license the project, the state noted that it will likely request at least four studies. This is a preliminary list and the state noted they may want to see the project area before making a final decision on studies. The four studies initially identified include:

1) Bypass flow study (between the low level outlet and powerhouse tailrace)—primarily for habitat, but they may also need to look at aesthetics as well depending on the reach. This would likely be a Delphi or modified-IFIM (field based) analysis with little-to-no modeling.

2) Habitat below the tailrace—This would likely be a full-blown PHABSIM one-dimensional transect-based model. The length of the study reach (i.e. how far downstream from the tailrace would the study extend) was discussed. Although not mentioned in the meeting, GSE could envision VANR requesting the study extend to the North Branch's confluence with the Winooski River.
3) Water quality—This would likely look at temperature and dissolved oxygen above, within, and below the project area. It may include bi-weekly profiles of the impoundment or continuous loggers in the impoundment, plus loggers in the river reaching downstream of the powerhouse all the way to the mainstem Winooski River.
4) Water level study, including mapping the following along the entire perimeter of the Wrightsville Reservoir—littoral zone substrate mapping, submergent aquatic vegetation (SAV), emergent aquatic vegetation (EAV), and wetlands. WEC questioned the need of such a study when the fluctuation is already limited to 1-2 feet, noting that natural lakes fluctuate more than that amount.

Based on the above list, a scoping outline was developed with the assistance of consulting firm Gomez and Sullivan. A summary is provided in Table 3-2.

Table 3-2. Wrightsville FERC Relicensing Scoping Outline

**Wrightsville Hydroelectric Project**
**Integrated Licensing Process Schedule**
**(assumes starts on 5/1/2017, 5.5 yrs ahead of license expiration)**

| Activity | Responsibility | Required Time Frame | Citation | Deadline |
|---|---|---|---|---|
| File Notice of Intent (NOI) and Pre-Application Document (PAD) | Applicant | At least 5 (but no more than 5 1/2) years before existing license expires | 18 CFR § 5.5(d) | 5/1/2017 |
| Hold Initial Tribal Consultation Meeting | FERC | Within 30 days of filing of NOI & PAD | 18 CFR § 5.7 | 5/31/2017 |
| Notice NOI/PAD and Issue Scoping Document 1 (SD1) | FERC | Within 60 days of filing of NOI & PAD | 18 CFR § 5.89(a) | 6/30/2017 |
| Site Visit and Hold Scoping Meeting | FERC | Within 30 days of issuance of SD1 | 18 CFR § 5.8(d) | 7/30/2017 |
| Comment on PAD and SD1; Submit Study Requests | Stakeholders | Within 60 days of issuance of SD1 | 18 CFR § 5.9(a) | 8/29/2017 |
| File Proposed Study Plan (PSP) | Applicant | Within 45 days of deadline for filing comments on PAD and SD1 | 18 CFR § 5.9 | 10/13/2017 |
| Hold Study Plan Meeting | Applicant | Within 30 days of deadline for filing PSP | 18 CFR § 5.11(e) | 11/12/2017 |
| Comment on Proposed Study Plan | Stakeholders | Within 90 days of filing PSP | 18 CFR § 5.12 | 2/10/2018 |
| File Revised Study Plan (RSP) | Applicant | Within 30 days of deadline for filing comments on PSP | 18 CFR § 5.13(a) | 3/12/2018 |
| Comment on Revised Study Plan | Stakeholders | Within 15 days of filing of RSP | 18 CFR § 5.13(b) | 3/27/2018 |
| FERC Issues Study Plan Determination | FERC | Within 30 days of filing of RSP | 18 CFR § 5.13(c) | 4/26/2018 |
| Initiate Formal Study Dispute Resolution Process (if necessary) | Agencies with conditioning authority | Within 20 days of issuance of Study Plan Determination | 18 CFR § 5.14(a) | 5/16/2018 |
| File Response to Study Dispute(s) (if necessary) | FirstLight | Within 25 days of Notice of Study Dispute | 18 CFR § 5.14(i) | 6/10/2018 |
| FERC Dispute Panel Issues Finding (if necessary) | Dispute Panel | Within 50 days of Notice of Study Dispute | 18 CFR § 5.14(k) | 7/5/2018 |
| FERC Issues Determination on Study Dispute (if necessary) | FERC | Within 70 days of Notice of Study Dispute | 18 CFR § 5.14(l) | 7/25/2018 |
| Conduct Field Studies | Applicant | Pursuant to approved SP | 18 CFR § 5.15 | 2018, perhaps 2019 |
| File Study Progress Report(s) | Applicant | Six months after studies begin | 18 CFR § 5.15(b) | 12/1/2018 |
| File Initial Study Report | Applicant | Pursuant to approved SP or no later than 1 year after approval of SP | 18 CFR § 5.15(c)(1) | 4/26/2019 |
| Hold Study Results Meeting | Applicant | Within 15 days of filing of initial study report | 18 CFR § 5.15(c)(2) | 5/11/2019 |
| File Study Results Meeting Summary | Applicant | Within 15 days of study results meeting | 18 CFR § 5.15(c)(3) | 5/26/2019 |
| File Meeting Summary Disagreements | Stakeholders | Within 30 days of filing of study results meeting summary | 10 CFR § 5.15(c)(4) | 6/25/2019 |
| File Responses to Disagreements | Applicant | Within 30 days of filing of meeting summary disagreements | 18 CFR § 5.15(c)(5) | 7/25/2019 |
| Resolve Disagreements | FERC | Within 30 days of filing of responses to disagreements | 18 CFR § 5.15(c)(6) | 8/24/2019 |
| File Updated Study Report (if applicable) | Applicant | Pursuant to approved SP or no later than 2 years after approval of SP | 18 CFR § 5.15(f) | 4/26/2020 |
| File Preliminary Licensing Proposal (PLP) or Draft License Application | Applicant | No later than 150 days before final application is filed | 18 CFR § 5.16(a) | 5/4/2020 |
| Comment on PLP, Additional Information Requests (if necessary) | Stakeholders | Within 90 days of filing of PLP or draft license application | 18 CFR § 5.16(e) | 8/2/2020 |
| File License Application | Applicant | No later than 24 months before existing license expires | 18 CFR § 5.17(a) | 10/31/2020 |

These steps only occur if there is a disagreement with a study.

Based on current information, it will be an expensive and complicated effort to renew the plant's license. An initial budget estimate received for the project estimated costs as high as $300,000. This is a major investment in the project and must be analyzed relative to the energy production and benefits created from the plant. WEC will perform a cost/benefit analysis to better understand the cost of license renewal relative to the benefits from the project.

## Sheffield Wind

WEC entered a contract to purchase power from the Sheffield Wind facility for a 10% entitlement to power from the 40 MW project. The project was under construction in 2011 and achieved commercial operation on October 19, 2011 in Sheffield, Vermont. WEC's nameplate entitlement is 4,000 kW, and WEC receives a proportionate share of renewable attributes associated with the output from the facility, as well as capacity. Energy production will vary with wind speeds, which are seasonal and diurnal, but an annual capacity factor near 25% is projected for energy production at the facility.

**Hydro Quebec US Purchase Power Agreement (HQUS PPA)**

WEC, along with other Vermont utilities, petitioned the Vermont Public Service Board in 2010 in Docket 7670 to approve various agreements related to obtaining power from H.Q. Energy Services (US) Inc. through a Purchase Power Agreement (HQUS PPA). WEC is participating as a buyer of power under the Vermont Public Power Supply Authority (VPPSA) through a sub-allocation arrangement. WEC will be allocated energy products from the HQUS PPA through VPPSA in the amount of 4,000 kW from November 1, 2016 through October 31, 2038.

The energy from this contract will be delivered seven days a week, from hour ending 08:00 to hour ending 23:00, on a firm basis through an Internal Bilateral Transaction (IBT) settled through the ISO-NE markets. There is no capacity accompanying the energy, but environmental attributes will be delivered with a minimum guarantee that 90% of the power will come from hydro resources.

WEC has a contract entitlement from this resource of up to 4,000 kW. Currently WEC assigns this power to Vermont Electric Cooperative (VEC) through a sleeve arrangement. Starting on November 1, 2016, WEC is contractually required to take back this power to meet its load if other committed resources are insufficient. The amount of power WEC may take is specified by a formulaic process in the sleeve agreement. This agreement states:

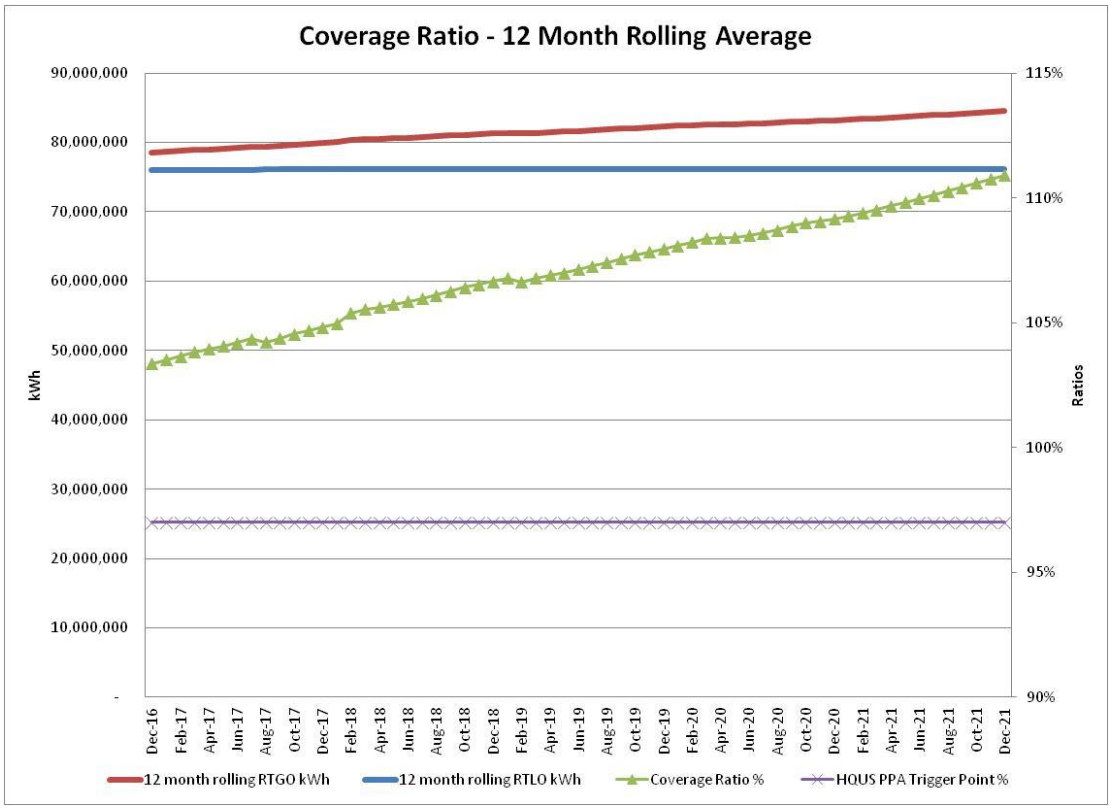
- WEC must begin to take power back from VEC with a one year notice period if its coverage ratio[19] falls below 97% over the preceding prior 12 month period;
- The amount of power WEC takes is defined by a formula which includes a coverage band tied to the amount of power needed to bring WEC's coverage ratio to 100%;
- Once WEC takes power back, it must retain that power until the end of the contract term in 2038;
- WEC can temporarily take back power in the event of an unplanned outage from an existing resource.

Based on WEC's 2017 load outlook and projections of future resources, WEC will not reach the 97% coverage ratio in the next five years. In fact, based on increasing energy production at Coventry and flat load, it could be as far out as 2032 before WEC needs the HQ contract. WEC will monitor its needs annually and adjust its outlook with time. For illustrative

[19] Coverage ratio is defined as the ratio of the amount of generation from the existing resources in WEC's portfolio divided by WEC's RTLO load and is calculated on a rolling twelve-month basis.

purposes, below is a summary of WEC's five year outlook.

Figure 3-1. HQUS PPA Ratio Analysis Outlook




Once WEC reaches the 97% coverage ratio, WEC will notify VEC that it will take back an amount of power within one year that will result in a WEC coverage ratio of 100%, capped at WEC's full allocation of 4.0 MW. WEC's coverage ratio will be calculated monthly and the process of taking back power from VEC will continue until WEC's full allocation of the HQUS PPA is returned.

## 3.2. WEC Existing Energy Resources versus Projected Energy Requirements

WEC has several power contracts and resources it uses to cover its load requirements. As displayed in Figure 3-2, WEC is well positioned into the planning horizon to hedge load against volatile power market prices, with a mix of stably priced contracts and owned generation resources.

Figure 3-2. Annual projected existing resource output compared to the expected value of WEC's real-time load obligation

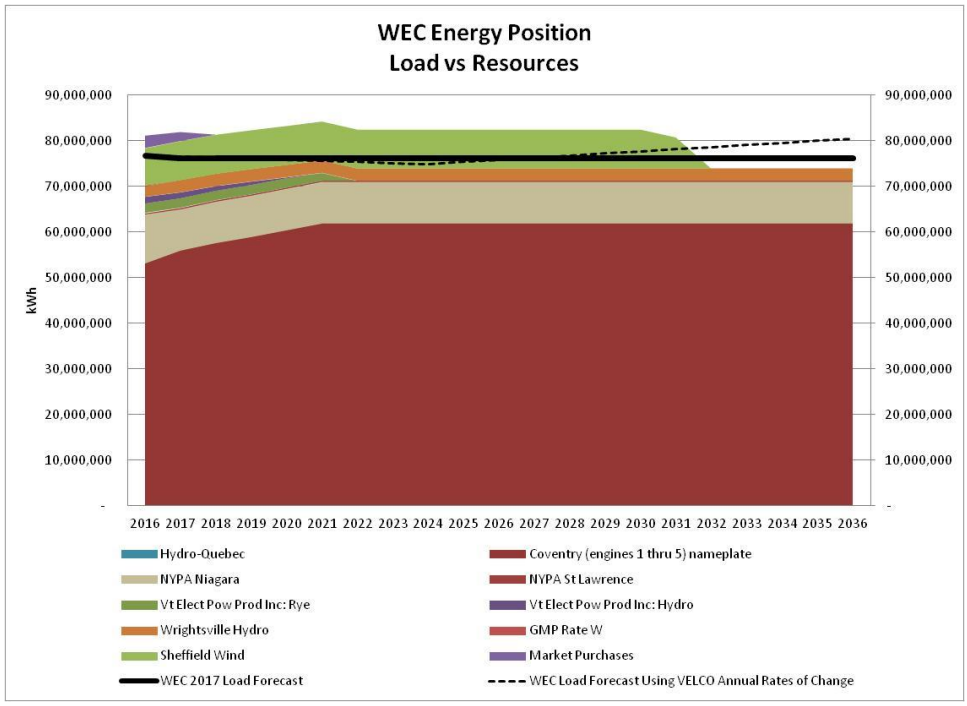
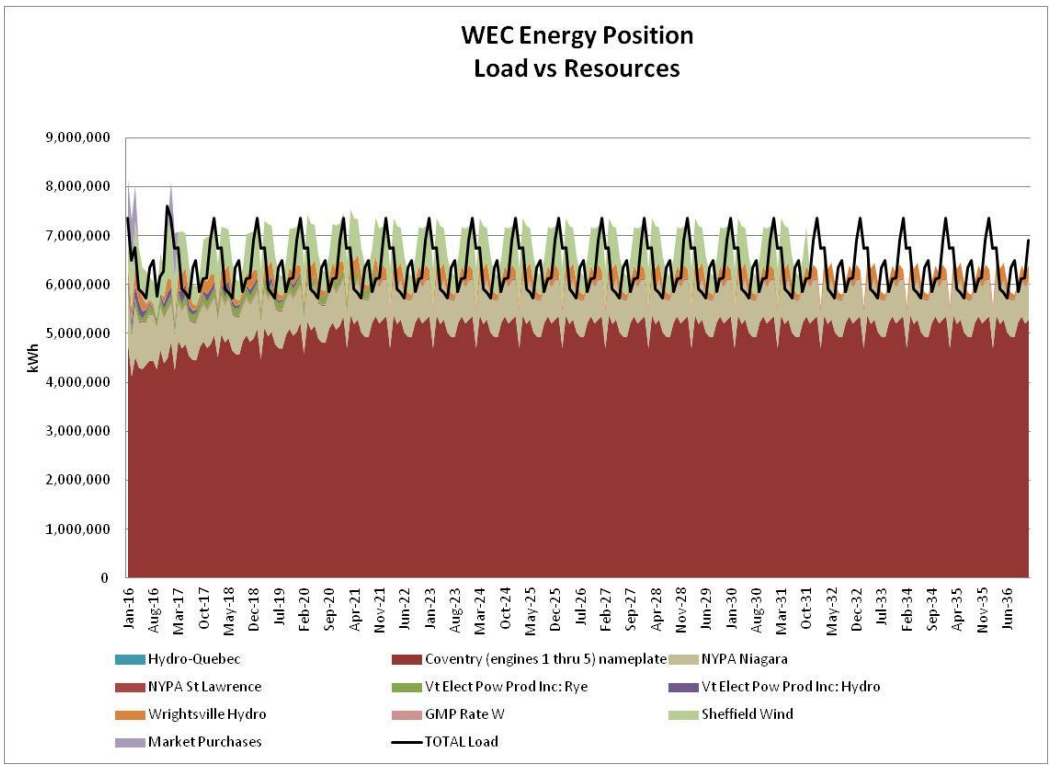



Figure 3-3. Monthly projected existing resource output compared to the expected value of WEC's real-time load obligation



As Figures 3-2 and 3-3 illustrate, in the near term WEC has excess power relative to its needs to serve its members' energy use. From 2016 through 2017, WEC averages 5% more power from committed power supply resources than its load requirements. As Coventry production grows, WEC projects to steadily increase its coverage ratio from 105% in 2016 to 108% through 2031. Once the Sheffield Wind contract expires (October 2031), then WEC will drop to roughly a 97% coverage ratio; at which point the HQUS PPA could be triggered.

The impact to WEC is that for the next several IRP filings it does not need to make major or long-term resource decisions. In a broader 20 year outlook, WEC's load and resource commitments also show that it is not facing major resource decisions for the foreseeable future. When WEC starts to see a shortfall, the HQ US PPA will begin and cover the shortfall well past the planning period.

In effect, WEC's current IRP filing represents an assessment of WEC's current and long-term position and identifies when the HQ contract will be triggered, rather than a justification of any new power supply commitments.

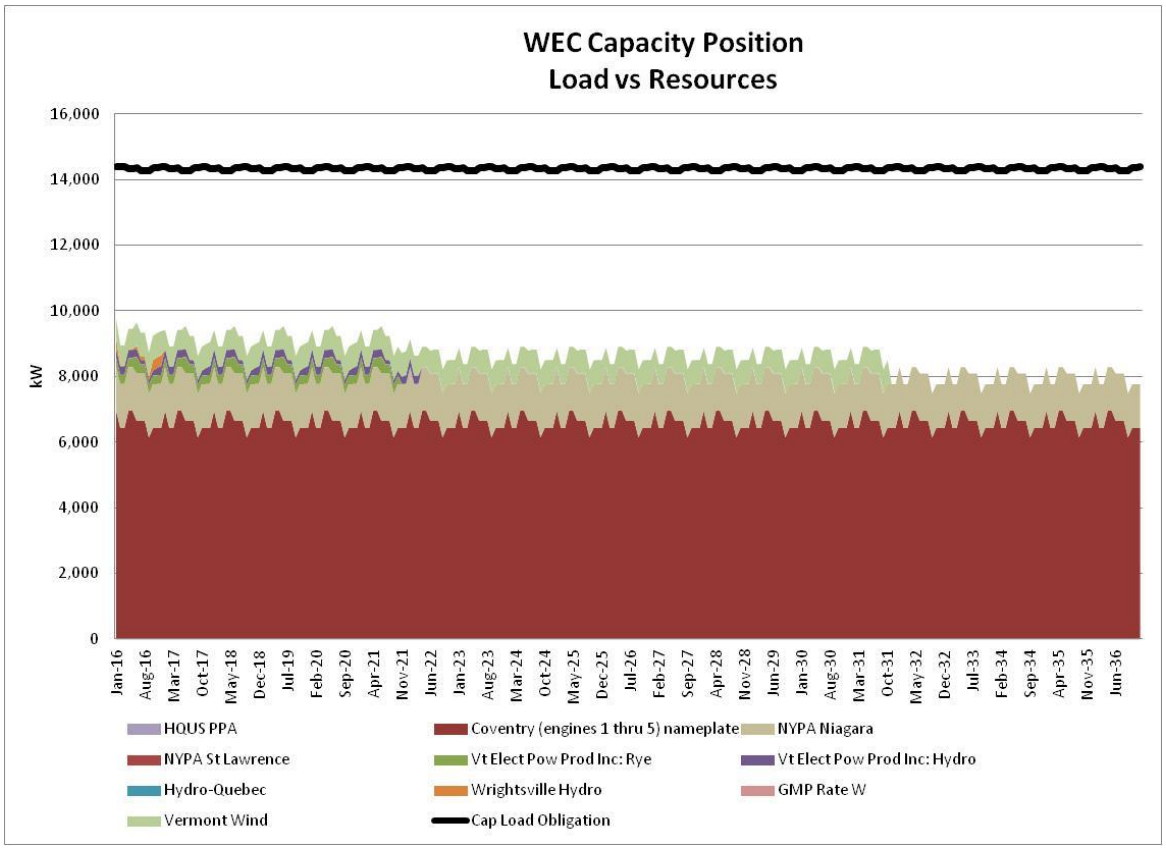
While many Vermont utilities have large shortfalls or gaps of power supply compared to load requirements, and are considering replacement sources of power due to expiring contracts, WEC is well positioned long-term with stably priced and long-term power commitments. As a result, WEC is using its IRP to analyzing impacts on its existing power supply mix of major operational, market, and regulatory factors affecting cost, cost variance, and emissions profiles.

## 3.3. WEC Existing Capacity Resources versus Projected Capacity Requirements

While WEC has energy resources sufficient to cover its load, WEC does show a shortfall or gap in its capacity obligation, as shown in Figure 3-4. After the HQ VJO contract expired, WEC lost 2.6 MW of capacity credits. As a result of this expired contract and lower FCM levels for WEC's other sources, WEC shows a shortfall of roughly six MW. At this point in time it will be roughly 60% covered, leaving a 40% open position between supply and capacity obligation. From there, the gap remains fairly steady through the end of the study period.

One of the reasons for the increasing gap is that the HQUS contract does not provide WEC with any additional capacity, as it is an energy only contract. However, in the short term this gap is manageable, as the cost of capacity from the market is known three years in advance, and the market price is low relative to the cost to build or contract for alternative capacity.

Figure 3-4. Monthly projected existing resource capacity market credit compared to the expected value of WEC's capacity market obligation




WEC must balance its need to hedge capacity not only with costs, but the fact that it is already long on energy. Therefore, power resources that provide both capacity and energy are not desirable to WEC as it tries to keep its positions balanced in both markets. Additionally, the price of capacity is known three years in advance in the ISO-NE markets. Therefore, WEC has sufficient time to react to any dramatic price increase and can hedge its open capacity position if it determines there is a more cost-effective option available.

## Short Term Contracts

WEC actively seeks interest in a capacity contract to help fill its gap. Thus far it has not been able to secure an agreeable transaction. The Co-op has been in discussions with developers, owners of existing resources, and marketers. Many of these counterparties are looking for bundled deals (energy, RECs, capacity).

WEC is currently negotiating for a four MW capacity contract with a developer that

owns generation outside Vermont. The counterparty has found market buyers for energy and RECs, which leaves capacity from the project available. To protect WEC's interest in this potential resource, this IRP write up provides only general information. The capacity is from a renewable resource, which is consistent with WEC's goals to support renewable sources of power. The ultimate plan is to enter a contract for capacity that insulates WEC from higher FCA prices. The developer is interested as it would like WEC, as the market participant, to take on the role of settlement with the ISO-NE. Hence in exchange for the developer avoiding the complexity of becoming an ISO-NE market participant, WEC will use its settlement with the ISO-NE to get the capacity into the market.

Other potential sources of capacity may include the TransCanada hydro facilities. WEC is working with other Vermont utilities regarding this source.

**Battery Storage and Demand Side Efforts**

Battery storage may also help close the gap for capacity. If WEC is able to successfully install battery storage and control load at the time of the ISO peak, it may be able to lower WEC's capacity obligation and close the gap from the demand side. Hence it will also look at battery storage in effort to control WEC's capacity gap in the FCM market. WEC is working with a project developer and plans to conduct a cost/benefit analysis and feasibility study within a year.

WEC may also consider and explore other alternatives to reduce load at the time of the ISO peak, such as behind-the-meter controllable loads and peak shaving rate programs. WEC notes load control and rate design programs are a more challenging endeavor, given the need to have many points of uptake by consumers to have a meaningful impact. Regardless, WEC will monitor and research demand side efforts that may yield value for a utility that is predominantly residential.

**Use of Generation Resources**

WEC's investment in the SRS at Coventry will increase the plant's capacity level in the future. It expects after six months a new baseline of production will be set and this will increase the level of capacity Coventry can produce in the FCM markets. Ideally, WEC will be able to increase the plant capacity by 2.0 MW. Before WEC takes a market obligation in the FCM, it seeks to demonstrate the plant can functionally and stably produce at these higher levels.

WEC also notes the pace of net metering installations in 2017 has been explosive. This will lower WEC's capacity obligations in the future and a decline in WEC's FCM load obligation will occur over time due to net metering. This reinforces the plan to enter short-term contracts for capacity, as WEC's need for capacity may ultimately be lowered due to demand side efforts and increases from other sources of generation.

Converting Wrightsville to a load reducer will also help reduce WEC's FCM obligation and close the gap. The ISO creates a capacity need for the entire region and it uses roughly a 15% adder to the region's peak needs. This buffer to the FCM obligation is avoided if WEC can lower its load obligation at the time of the ISO peak. For every 1 kW reduced, it is worth a reduction to the capacity obligation of 1.15 kW.

The combination of actions and hedges noted above is expected to fulfill WEC's long-term capacity need.

# 4. Legislative & Regulatory Directives

## 4.1. Act 99 Net Metering

The Vermont legislature passed sweeping changes to net metering laws through Act 99 in 2014. As part of this legislation, the PSB issued a ruling in 2016 requiring WEC and all Vermont utilities to issue new net metering tariffs. The changes in the tariffs affect existing and new systems installed after January 1, 2017.

The PSB issued an order in August 2016 in which it summarized changes to the net metering program as a result of the legislative directive from Act 99. The PSB Order states:

> In April of 2014, the Legislature passed Act 99, which required that the Board establish a revised net-metering program pursuant to the criteria and standards set forth in 30 V.S.A § 8010. Section 8010 directs the Board to develop a net-metering program that:
>
> (A) advances the goals and total renewables targets of this chapter and the goals of 10 V.S.A. § 578 (greenhouse gas reduction) and is consistent with the criteria of subsection 248(b) of this title;
>
> (B) achieves a level of deployment that is consistent with the recommendations of the Electrical Energy and Comprehensive Energy Plans under sections 202 and 202b of this title, unless the Board determines that this level is inconsistent with the goals and targets identified in subdivision (1)(A) of this subsection. Under this subdivision (B), the Board shall consider the Plans most recently issued at the time the Board adopts or amends the rules;
>
> (C) to the extent feasible, ensures that net metering does not shift costs included in each retail electricity provider's revenue requirement between net metering customers and other customers;
>
> (D) accounts for all costs and benefits of net metering, including the potential for net metering to contribute toward relieving supply constraints in the transmission and distribution systems and to reduce consumption of fossil fuels for heating and transportation;
>
> (E) ensures that all customers who want to participate in net metering have the opportunity to do so;
>
> (F) balances, over time, the pace of deployment and cost of the program with the program's impact on rates;

(G) accounts for changes over time in the cost of technology; and

(H) allows a customer to retain ownership of the environmental attributes of energy generated by the customer's net metering system and of any associated tradeable renewable energy credits or to transfer those attributes and credits to the interconnecting retail provider, and:

(i) if the customer retains the attributes, reduces the value of the credit provided under this section for electricity generated by the customer's net metering system by an appropriate amount; and

(ii) if the customer transfers the attributes to the interconnecting provider, requires the provider to retain them for application toward compliance with sections 8004 and 8005 of this title. [20]

WEC filed its Net Metering tariff in October 2016 to comply with the new net metering rules. It amended this filing in January 2017 based on feedback from the PSB to WEC's October filing. In its tariff WEC is converting its Grid Service Fee plan participants (those members with distributed generators installed after July 2014) to its Legacy plan structure to comply with the PSB ruling. After 10 years of operation, all pre-existing systems (those installed prior to January 1, 2017) will be paid the statewide blended rate for excess generation per the new PSB rules. Prior to this 10 year anniversary they will be paid at WEC's highest energy block in its retail rate design. Please see Appendix for a copy of WEC's net metering tariff.

WEC has 255 members, totaling 1,661 kW, signed up under the pre-existing net metering programs (these are systems installed before January 2017). These installations are approximately 10% of WEC's 2016 retail peak load level. This equates to an amount of energy produced from net metered systems of roughly 2.6% of WEC's 2017 annual retail sales.

The pace of new installations (after January 1, 2017) has been tremendous. As of June, WEC already has 72 members signed up, totaling 1,412 kW. If this pace continues, WEC will see an additional 2,800 kW of net metering installed in one year (2107). That will bring the total to 4,400 kW of installed distributed generation, which is 28% of WEC's peak. WEC is very concerned about the pace of installations and questions the sustainability of the existing Board rules.

[20] PSB Order Implementing the Renewable Energy Standard, issued June 28, 2016 Docket 8550

## 4.2. Act 56 Renewable Energy Standard

Act 56 created a Renewable Energy Standard (RES) for Vermont electric utilities that requires renewable energy totaling 55% of retail electric sales in 2017, with that requirement growing 4% every three years to 75% in 2032 (Tier I). Of these renewable resources, some (1% of retail sales in 2017 growing to 10% in 2032) are required to be new, small, distributed generators connected to Vermont's distribution grid (Tier II). The act also requires utilities to assist their customers in reducing fossil fuel consumption (Tier III).

The PSB summarized the requirements of Act 56 in its June 2016 Order:

> The Vermont Public Service Board ("Board") directs the implementation of the Renewable Energy Standard program ("RES"), which requires Vermont retail electric providers ("DUs") to acquire specified amounts of renewable energy, in the form of renewable attributes or Renewable Energy Credits ("RECs"), and to achieve fossil-fuel savings from energy transformation projects. Section 8 of Public Act No. 56 of 2015 ("Act 56") directs the Board to implement the RES by means of an "an order, to take effect on January 1, 2017," followed by a rulemaking.
>
> The RES establishes aggressive targets requiring utilities to procure renewable energy for the majority of their generation portfolios. In addition, the RES contains a first-in-the-nation program whereby a DU can meet their portfolio requirements by investing in projects that will reduce fossil-fuel consumption by their customers. These projects could include items like home weatherization projects to reduce fuel oil purchases by customers, the replacement of fossil-fuel-based heating systems with electric or biomass energy, or investments in clean forms of transportation like electric vehicles. In combination, these requirements will work to further reduce Vermonters' reliance on fossil fuels across a range of sectors.
>
> The structure of the RES is divided into three categories or tiers. The first tier ("Tier I") requires DUs to procure an amount of renewable energy equivalent to 55% of their annual retail electric sales for the year 2017. This amount increases by 4% every third January 1 thereafter, eventually reaching 75% in 2032.
>
> The second tier ("Tier II") requires DUs to procure an amount of renewable energy equivalent to 1% of their annual retail sales from distributed generation

> resources starting in 2017. This amount increases by three-fifths of a percent each year, eventually reaching 10% in 2032. Pursuant to Section 8005(a)(1)(C), Tier II resources are also counted as part of a DU's Tier I requirement.
>
> The third tier of the RES ("Tier III") requires that DUs either procure additional renewable distributed generation eligible for Tier II or acquire fossil-fuel savings from energy transformation projects. Energy transformation projects are those that reduce fossil fuel consumed by DU customers and the emission of greenhouse gases attributable to that consumption. For Tier III, the RES establishes a required amount of 2% of a DU's annual retail sales in 2017, increasing by two-thirds of a percent each year and reaching 12% in 2032.
>
> Act 56 created certain rules for the RES but left some issues to be resolved by the Board. Based on the requirements of Section 8 of Act 56, the Board has conducted and Board staff held a series of working group meetings and two workshops with a variety of stakeholders directed at identifying and resolving issues associated with the implementation of the RES. In addition, on March 15, 2016, the Board issued an interim order ruling on several aspects of the RES program. In this current Order, the Board establishes, where necessary, further parameters of the RES, ruling on those issues identified through the process described above, and directs DU's to comply with the RES in the manner described in this Order. [21]

WEC maintains a portfolio that is 100% renewable and therefore it has met the RES 55% renewable goals for 2017 (Tier I). More significantly, WEC has already exceeded the state goal of 75% renewable by 2032 with its existing (2016) mix of energy sources. WEC is a leader in renewable energy and only one of a few utilities in the nation that can boast a 100% renewable power supply mix. Since WEC has already exceeded the state's ultimate goal well over 15 years in advance, it does not need to change or plan for new sources of power to meet the state's RES Tier I requirement

In March 2016, WEC petitioned the PSB in docket 8550 for a determination that it qualifies as a retail electricity provider meeting the conditions in 30 VSA 8005 (b)(1)(A), which allows it to satisfy the distributed generation requirement of Tier II by accepting net metering systems within its service territory. The PSB approved this petition and WEC was granted the determination that it qualified as a 100% renewable retail electric provider (docket

[21] PSB Order Implementing the Renewable Energy Standard, issued June 28, 2016 Docket 8550

8714). The Board's order is included in the Appendix.

As noted above, Tier II requires electric providers to have distributive renewable generation comprising at least one percent of its annual retail sales for the year beginning January 1, 2017. WEC's renewable determination by the Board enables WEC to satisfy Tier II requirements by accepting net metering systems within its service territory. Therefore, WEC is not exempt from offering net metering as a renewable energy provider. Rather, it must offer net metering, but its members are not required to achieve the annual energy targets set forth in Tier II; WEC is relieved of the requirement to provide that 1% of its annual sales are provided by new net metering due to its 100% renewable status. Currently, WEC has 1,661 kW of distributed generation system installed in its service territory. This equates to an amount of energy produced from net metered systems of roughly 2.6% of WEC's 2017 annual retail sales. If the pace of deployment in the 2017 plan continues, WEC is projecting roughly 2.6% of its 2017 retail sales will be served by new net metering systems. This is well beyond the 1% required in the Tier II requirement.

Tier III has been referred to as the energy transformation Tier. This Tier's focus is on efforts that switch members away from fossil fuels in transportation and heating use to non-fossil-fuel energy sources. All utilities were required to create a plan to meet their Tier III obligations. A copy of WEC's plan is provided in the Appendix.

WEC's Annual Plan addresses its strategy to meet Tier III compliance obligation for 2017. Overall, WEC's Annual Plan describes:

1) Estimated Tier III compliance obligation for 2017;
2) Overall strategy to be implemented to meet the Tier III compliance obligation in 2017; and
3) Types of energy transformation projects that will be undertaken and anticipated number of participants.

WEC will offer a suite of energy transformation measures that have been vetted through the Technical Advisory Group (TAG) screening process. A fundamental component of WEC's plan is to emphasize and match TAG screened measures with heightened weatherization efforts.

Implementation of the projects described in WEC's Annual Plan will be closely coordinated with Vermont Energy Investment Corporation (VEIC) as the administrator of Efficiency Vermont, the statewide energy efficiency utility (EEU). In addition, coordination of

data collection, management, reporting, and evaluation and verification activities will be maximized to the extent possible with protocols and schedules already in place for WEC and Efficiency Vermont. In cases where entities other than VEIC and its subcontractors deliver WEC Tier III programs and services independently, WEC will ensure coordination of data collection and reporting to provide a single deliverable to regulators.

The parties have reached an understanding on the implementation of energy transformation projects for WEC members. Efforts will include the coordinated use of member and supply-side incentives, standards for measuring performance, and methods to allocate savings and reductions in fossil fuel consumption and greenhouse gas emissions among VEIC and WEC, with a strong emphasis on weatherization.

The eligible measures for WEC members are detailed below in Table 4-1. The foundation of WEC's Tier III program is found in statute V.S.A. Title10 § 581. Vermont has an aggressive policy goal of weatherizing 80,000 existing residences by 2020; WEC's Tier III program is, in part, intended to assist members to reduce the fossil fuels used today, as well as increase comfort and indoor air quality through comprehensive thermal energy improvements.

Vermont's RES establishes a required amount for Tier III compliance of 2% of a DU's annual retail sales in 2017, increasing by two-thirds of a percent each year and reaching 12% in 2032.

The calculation for this compliance amount for WEC for 2017 is shown in Table 4-1:

Table 4-1. Tier III Resource Targets and Measures

| | 2017 |
|---|---|
| Utility Sales (kWh) | **69,698,998** |
| Compliance Rate | 2.00% |
| MWh Minimum Target | 1,394 |
| Planned excess to assure attainment | 139 |
| **Combined MWh Target** | **1,533** |
| **Maximum Investment (ACP)** | **$ 83,639** |

| Measure | | EVT | WEC | TOTAL | MWh Savings | WEC incentive | ACP | EVT $ | WEC | CEDF |
|---|---|---|---|---|---|---|---|---|---|---|
| Weatherization Only (WX) | per unit | 40 | 15 | 55 | 61.1 | | | $1,400 | $600 | $0 |
| | Total | | | | 917 | $33,000 | $ 36 | | | |
| CCHP & WX | per unit | | 5 | 5 | 54 | | | $ 700 | $ 250 | |
| | Total | | | | 270 | $1,250 | $ 5 | | | |
| Heat Pump Water Heaters | per unit | 25 | 10 | 35 | 16.5 | $250 | | $600 | $250 | $0 |
| | Total | | | | 165 | $8,750 | $ 53 | | | |
| Solar Hot Water Heaters | per unit | 1 | 1 | 2 | 21.0 | $1,000 | | $950 | $500 | $1,000 |
| | Total | | | | 21 | $1,000 | $ 48 | | | |
| Charging Stations-L2 Work/public | per unit | | 4 | 4 | 9 | $0 | | $0 | | $0 |
| | Total | | | | 37 | $0 | $ - | | | |
| Pellet Boilers (no Wx) | per unit | 3 | 1 | 4 | 179.0 | $1,000 | | $2,000 | $1,000 | $3,000 |
| | Total | | | | 179 | $4,000 | $ 22 | | | |
| | | | | Sum of WEC Tier 3 incentives | | $ 48,000 | | | | |
| | | | MWh savings estimate | | 1,588 | | | | | |

As noted in the top portion of Table 4-1, WEC's compliance target is 1,394 MWH. Adding a ten percent buffer to this estimate for planning purposes gives WEC a year one target of 1,533 MWH. The "maximum investment" (alternate compliance payment/ACP) represents the Co-op's internal maximum potential investment to achieve a particular goal of fossil fuel reduction among its members. With a first year budget of $48,000, this equates to a cost per kWh equivalent of 3.4¢ per kWh (compared to the ACP of 6¢ per kWh).

WEC will implement programs and measures that it feels are in the best interest of its consumer-owners. While many of the programs involve incentive dollars, WEC is concerned that some of the mandates will work to raise member rates. In effect, the negative side of regulatory mandates is that they are new cost drivers, and ultimately members will see upward pressure on their rates. WEC seeks to reach a balance between responding responsibly to mandates and new laws while looking out for its members in terms of rate pressure and added expenses to the cost of service.

Using the Alternative Compliance Payment rate of 6¢ per kWh, WEC's maximum budget for incentives, program delivery, and administration is $83,639. Based on WEC's anticipated offering of measures combined with weatherization WEC plans to spend $48,000 in incentive dollars in its first year effort. WEC plans to do its own program reporting in the first year, and therefore costs and dollars are limited to incentives.

## 4.3. Automated Metering Infrastructure (AMI) and Other Control Technology

WEC has replaced all but four of the existing kWh meters of its roughly 10,800 meter system with AMI digital meters. The AMI technology has been fully integrated with WEC's Outage Management System (OMS), allowing real time active monitoring of the Distribution System and a wide spectrum of data gathering. In addition to the AMI data collection

attributes, the technology is being used to verify reported power outages and to confirm restoration. The inherent features of the AMI system provide for improved operation efficiency and service to the Co-op's members.

The Supervisory Control and Data Acquisition (SCADA) technology deployed on WEC's electrical system utilizes the data backhaul infrastructure of the AMI system for secure data transmission. SCADA monitoring devices have been installed on critical switches and equipment at all substation locations. The SCADA system provides real time status of the load break switches and circuit reclosers that interconnect the substations with the transmission grid. The system also monitors the voltage, present kW load, and peak demand at each of the substation main feeders. The SCADA system was fully integrated with WEC's outage management systems in 2014. The AMI and SCADA systems combined have significantly improved the Co-op's ability to more efficiently manage widespread outages, reducing restoration times and providing enhanced operational safety for line crews and the general public.

## 4.4. Changing Energy Landscape

WEC recognizes there has been a significant shift in electric planning and regulation. This changing landscape requires WEC to think about the future and how it operates in a new electricity environment. WEC needs to prepare for a modernized and dynamic electric grid that includes increased distributed generation and more demand side management tools. As noted earlier, WEC's supply side is set through the 20 year planning period. However, changes to load and work on demand side issues generate a number of key questions that are most relevant to WEC at the time of its IRP filing. WEC sees its ability to manage electric energy demand through energy efficiency, load management, and electric energy storage as the next frontier.

WEC looks to explore tools and technologies to cost effectively meet electric demand while advancing state policy objectives, such as the Renewable Energy Standard and new net metering laws, storage, and rate design. Energy sources still must be balanced, moment by moment, with energy consumed. That said, the trend from large, central power plants to more distributed and locally sourced supply resources is on the increase.

Also, more intermittent resources, such as utility scale wind and solar, continue to be deployed in Vermont and in the region. This has provided a new paradigm for ISO-NE to respond to grid reliability and generator dispatch protocols. Typically, generators are

controlled to respond to demand. In today's environment, loads are becoming less predictable with the increase in distributed generation and utility scale solar challenging the supply side dispatch paradigm.

Other drivers continue to put cost pressure on WEC, such as other New England state polices for increased renewable power and incentives to maintain large power plants to meet demand. Winter reliability costs as well as rising capacity and transmission costs continue to put financial pressure on WEC, while loads are flat to declining. This is a recipe for upward pressure on rates.

Connecticut lawmakers recently announced intentions to seek legislative changes to allow the Millstone nuclear power plant to sell directly to the state. A report from the Associated Press noted a group of Connecticut lawmakers are seeking "to reduce any risk the Millstone Power Station will close" due to economic circumstances "by allowing it to sell power directly to the state." State Rep. Lonnie Reed said, "I really consider it a pre-emptive strike to deal with the realities of the energy economics." Currently, power generated by Millstone is "sold like any other commodity through hedge funds and Wall Street firms that add their own fees," according to Millstone spokesman Ken Holt. The article added that Holt "said it would ultimately benefit ratepayers to cut out the middleman." Holt said, "We like stability. We like a known return." Holt continued, "The price of natural gas is depressing prices for electricity across the country, especially in New England...Millstone is not immune to those pressures." [22]

Massachusetts is moving toward more renewable sources of power and is contemplating becoming 100% renewable in all of its energy uses by 2050, which is similar but more aggressive than Vermont's goal. A bill has been introduced from Massachusetts state representatives that would commit the state to obtaining 100% of its energy from renewable resources. The bill requires total renewable electrical generation by 2035 and a phase out of fossil fuels across all sectors by 2050.[23]

New York has created sweeping reforms and changes in its energy landscape as well. The New York Commission issued its Order Adopting Regulatory Policy Framework and Implementation Plan in its proceeding entitled Reforming the Energy Vision (REV) in February 2015. In the state's energy plan, its goal is to cut greenhouse gas emissions 80% by

---

[22] *Connecticut Lawmakers Seek To Allow Millstone To Sell Power Directly To State. The AP (1/19/2017)*

[23] *Massachusetts Bill Would Require Complete Renewable Use By 2050. The AP (1/21/2017)*

2050. The plans from the legislation call for 1) Enhanced customer knowledge and tools that will support effective management of the total energy bill; 2) Market animation and leverage of customer contributions; 3) System wide efficiency; 4) Fuel and resource diversity; 5) System reliability and resiliency; and 6) Reduction of carbon emissions. These six elements call for increased renewables, energy efficiency measures, and distributed generation planning by distribution utilities, as well as incentives to keep nuclear plants open, such as the Fitzpatrick plant in Oswego, NY. These changes impact the regional grids within which WEC works. Being aware is important: planning with state mandates rather than the open market system creates new uncertainties.

## 4.5. State of Vermont Energy Goals and Comprehensive Energy Plan

The Comprehensive Energy Plan (CEP) addresses Vermont's energy future for electricity, thermal energy, transportation, and land use. In the 2016 CEP, Vermont established the goal of sourcing 90% of all energy use in the state from renewable resources by 2050 as a way to meet the statutory goal, established in Act 168 of 2006, of achieving a 50% reduction in carbon levels from a 1990 baseline by 2028 and a 75% reduction by 2050. It is important to note the reference to energy in the CEP is not limited only to electric utilities, but applies to all sectors including transportation, heating, and process uses of fossil fuels.

Meeting the CEP goal of 90% renewable resources will require major plans and bold changes for everyone in Vermont. The plan also recognizes that we must pursue the goals responsibly, ensuring overall energy costs for our residents and businesses remain regionally competitive.

WEC is well positioned to meet the CEP goal before the 2050 date as its underlying investments and contracts in power supply are comprised entirely of renewable resources. While today WEC sells roughly 60% of its renewable attributes through REC sales to regional markets, WEC can retire these RECs as needed to comply with state goals.

Vermont's Comprehensive Energy Policy notes:

> Electric energy storage technologies are maturing quickly, as are technologies for automating and aggregating control of many different kinds of end uses (beyond the water heater controls that have been deployed for decades). Electric vehicles and heat pumps present new challenges and opportunities. Taken as a whole, these challenges present a new grid paradigm in which both demand and supply have both controllable

and non-controllable (but forecastable) aspects.[24]

An integrated grid is now possible because of the proliferation of information technology tools throughout the grid — at supply, on the grid itself, and at the end use. This provides the opportunity to optimize the grid in a way not possible before, with significant yet uncertain potential to contain overall and per unit costs. This paradigm informs Vermont's approach to both managing and meeting electric service demand, as this CEP describes.[25]

Retail electric costs are more than the moment by moment or long term costs of energy; they are also the costs of building and maintaining transmission and distribution infrastructure, generation capacity for peak times, and utility operations. ….Utility regulation by the Public Service Board establishes the structure and process for determining total utility revenues and how those revenues are collected from each customer. The design of rates for each customer class is intended to reflect the costs caused by those customers' use of the electric system. This minimizes subsidization of any customer class by other classes, and is considered economically efficient.[26]

Utilities and their regulators are guided by the policies established in Vermont law, which include at their core a goal of least cost electric service, including economic and environmental costs, consistent with the principles identified in Chapter 3 of this CEP. Per unit electric rates reflect all these costs and their allocation, divided among all of the customers, kilowatt hours of energy, and kilowatts of power delivered. Seeking the lowest electric rates and bills, therefore, includes:

- Reducing electric use and acquiring least cost energy and capacity, to avoid direct costs;
- Lowering peak energy use and distributing generation close to load, to reduce Vermont's share of regional transmission costs and avoid the need to build new electric infrastructure; and
- Using existing electric transmission and distribution infrastructure to the fullest, to share its cost over as many energy units as possible and thereby lower rates.[27]

At a high level, global trends in the enabling communication technology and distributed energy resources create opportunities for improvements in the costs, reliability, and

[24] 2016 CEP p 181

[25] 2016 CEP p 181-182

[26] 2016 CEP p 182

[27] 2016 CEP p 182

> environmental performance of the electric utility sector. To facilitate the change, complementary policy, regulation, and utility efforts will be needed sooner rather than later. Distributed energy resources and communications capabilities are still evolving, but the path is relatively clear. Distributed energy resources such as solar and wind, combined with distributed storage, flexible loads (such as electric vehicles and controllable devices), and a centrally managed platform, offer great potential for improving the grid's performance. The central question is: How do regulators, system operators, and electric distribution utilities need to evolve the system to remove barriers, enable the distributed grid to emerge, and motivate the DUs to function as a cooperating partner in facilitating these changes.[28]

WEC is keeping options open and looking to the future to guide it through a changing industry of decentralized generation and changing consumer behavior and loads. As a small utility it will work collaboratively with others in Vermont and the region. It will look for lessons learned in rate design as well as demand controls. Rather than reinventing the wheel, WEC will look to make use of others' best efforts and adopt working models to meet the membership's needs. It needs to do this with constant awareness of the cost to serve. WEC is the most rural utility in the state, and rates and bills matter to the membership. Decisions to spend money on future efforts must also be made in a manner that is mindful of financial pressures along with the need to respond to a changing utility landscape.

### 4.5.1. Energy Efficiency and DSM

The state's Comprehensive Energy Plan also discusses impacts of energy efficiency and focuses on demand side elements. Specifically, the CEP notes the following key elements that WEC takes into account in its future delivery of net metering, energy transformation efforts of Act 56, and other demand efforts:

> Significant efforts to reduce electric demand should not be translated into a policy in which all increases in electric energy and demand/consumption are avoided. Electric energy must be used efficiently and strategically. As other chapters of the CEP point out, increases in electric energy consumption in certain sectors and for certain end uses are probably in the best interests of the state. For instance, Chapter 8 calls for policies that will facilitate increases in plug-in electric vehicles, and Chapter 7 discusses a hypothetical fuel mix for meeting the 90% renewable goal by 2050 whereby some existing fossil fuel heating is switched to electric heating, which would require an

[28] 2016 CEP p 195

> increased penetration of cold climate heat pump technology.
>
> Electric energy DSM is not at odds with such policies and concepts; it is another tool to facilitate their implementation. The goal is to use the cleanest, most efficient, most cost effective energy for any particular end use. As this chapter describes in detail, electric efficiency programs have potential to save Vermonters money on their electric bills while providing the state with significant economic and societal benefits.
>
> Since 2000, the EEUs have acquired significant electric efficiency resources that have indeed met a significant portion of Vermont's electric needs, at a lower cost than would have otherwise been paid by ratepayers. Vermont currently leads the nation in our pace of acquiring electric energy savings through investments in energy efficiency. As summarized in a recent national benchmarking study commissioned by the DPS (and as shown in Exhibit 10-1), Vermont's electric EEUs deliver electric energy efficiency savings, above the median savings as a percent of sales, at the median levelized cost of energy saved of $0.03 per kWh.[29]

The CEP outlines various recommendations and strategies relative to demand issues that WEC sees as germane to its future:

> The DPS should collaborate with energy efficiency utilities and other stakeholders to better document and communicate the benefits of electric efficiency investment to the Vermont Legislature, ratepayers, and other stakeholders.[30]
>
> Peak reduction has the additional benefit of reducing the need for transmission and distribution infrastructure — if it occurs in areas where the system is constrained by load growth.[31]
>
> Support continued innovation and design of the most effective programs to assist ratepayers in achieving efficiency savings.[32]
>
> The DPS should encourage and facilitate innovative program designs and strategies to increase electric efficiency resource acquisition.[33]

---

[29] 2016 CEP p 201- 203

[30] 2016 CEP p 209

[31] 2016 CEP p 211 - 220

[32] 2016 CEP p 213

[33] 2016 CEP p 218

The DPS should also monitor PSB Docket 8316 for resolution related to AMI utilities other than GMP to take advantage of the new data---‑driven services being offered by the EEU.[34]

WEC designed its program plans to meet its Tier III obligations from Act 56 to focus on energy efficiency first and then offer incentives for home heat and water heat and other technologies. WEC will look at rate design and other demand based technologies to lower its peaks and attempt to reduce costs of infrastructure. Rate design work will occur in various stages, and the first step is to look at rate structures to respond to changes in the utility landscape in Vermont and regionally.

### 4.5.2. WEC's Goals for a Sustainable and Affordable Power Supply Mix

WEC has long been a leader in providing sustainable and affordable sources of power. WEC currently has investments in its underlying power supply commitment that originate as renewable sources of power. In fact, all of WEC's existing generation and power contracts reflect renewable based energy sources. WEC charted this course over the past decade in order to meet its members' goals of reduced exposure to fossil fuel and nuclear based power sources resources while reducing its environmental and emissions footprint.

WEC's investment in the Coventry landfill gas generator, which makes two thirds of WEC's power supply mix, is a low cost base load power source that is the anchor to WEC's sustainable commitments. WEC seeks to maximize Coventry's production to bring low cost renewable power to the grid and keep WEC members' costs as low as possible long-term. In addition, WEC's Wrightsville hydro facility is another owned generation resource where WEC seeks to maximize its value and keep WEC members' costs low.

WEC's other power supply commitments are contractually oriented and focus on hydro and wind based technologies. WEC seeks to maximize value from these contract commitments where possible, maintaining its goals for sustainability and affordability of its power mix and commitments, consistent with state and other jurisdictional goals and policy considerations.

[34] 2016 CEP p 220

# 5. Transmission & Distribution System

## 5.1. Distributed Generation and Impacts to the WEC Transmission & Distribution System

As noted in the 2016 Comprehensive Energy Plan:

> Apart from emergency preparedness, utility planning — e.g., integrated resource plans — must consider energy assurance. This includes preparatory actions that help the power stay on, such as careful vegetation management to clear trees away from power lines, and the strategic location of utility infrastructure to avoid risks in the first place (for example, siting substations and generators outside of floodplains and river corridors), or to make restoration of power easier (as by siting power lines along roadways).[35]
>
> The pace of innovation in the electric sector is increasing, especially for distributed energy resources. For instance, solar PV prices have fallen by nearly 60% in the last four years, while the number of electric vehicles in Vermont has increased by more than a factor of 10 and cold climate air source heat pumps are rapidly expanding in availability. During the past five years, Vermont utilities have completed deployment of a statewide smart grid, opening the door for modern information technology tools to manage the electric system. Changes wrought by evolving technology will challenge long-held paradigms that underpin utility business models, while also providing opportunities for utilities to increase their own fostering of innovation. Vermont must harness this innovation for ratepayers' benefit and use it to help meet our energy goals, thereby advancing economic, environmental, and health priorities.[36]

As noted previously, WEC completed a satisfaction survey of its membership in 2015. Members were asked to rank the importance of various attributes of their electric power and service. Reliability was given the highest importance rating among nine key factors. WEC members ranked reliable service above lower rates and friendly and knowledgeable service. With this directive, WEC seeks to harden its system and decrease the occurrence of power

[35] 2016 CEP p 273

[36] Ibid p 275

outages as well as decrease the time power is out when an outage occurs. To meet this challenge, WEC seeks to invest in its system as outlined in its CWP. WEC also sees that by responding to changes in industry practices, it will develop tools that will enhance and improve reliable service.

As a result of increased distributed generation, growing deployment of energy efficient technologies, and new plug loads, WEC seeks to explore a T&D system analysis to assess a changing industry. WEC will perform an assessment of its system to explore the impacts of growing distributed generation installed on the grid. WEC's analysis will be done to answer broad overarching questions:

- How much distributed generation can the T&D system accommodate?
- Does it matter by circuit/substation/size where distributed generation is located?
- What are the impacts to WEC's T&D system of new plug load (EVs, cold climate heat pumps, etc)?
- What power quality issues does WEC's T&D system need to address in light of a modernizing grid?
- What data is necessary to conduct a more comprehensive and transparent planning process?

WEC seeks to develop a scoping process that will allow it to specify the tools, process, and protocols to be developed in order to plan and operate a modern grid capable of dynamically managing distribution resources, as well as supporting retail markets that coordinate significant distributed generation investment and efficiently manage resources. Engineering and modeling efforts will be used to help convey how WEC plans, operates, and develops its system (where and which types of resources and equipment are best located on WEC's lines). WEC will also seek to balance distributed generation needs and grid modernization with total cost of its system and the impacts to members' rates and bills. In the near term, WEC plans to start a scoping process to outline work it will need to do in the future.

**Broader and Long-term Issues:**

WEC's operational practices required to operate the grid safely and reliably will continue to evolve based on increasing distributed generation and multi-directional power flows. Operating the distribution system going forward will require a combination of technologies and modernized and improved standards. In the longer term, WEC's plans must incrementally progress from adequately equipping the distribution system with monitoring and communication infrastructure to enabling intelligent, rapid, and precise control.

WEC looks toward deploying automated solutions across the system where it is appropriate and where it offers added value. WEC will focus in the near term on monitoring, observation, and a detailed assessment of its current system and its capabilities as well as its weaknesses. WEC will evaluate the effectiveness of existing systems to determine what modifications may be needed to operate the system safely. It is expected that forecasted distributed generation penetration levels, types, and locations will provide the basis to establish new policies, protocols, and visibility requirements. While WEC's current CWP process encompasses many of the goals noted in the IRP, these are specific items WEC seeks to examine and act on in the upcoming three years:

- Outline and provide an overview of WEC's T&D system;
- Develop and articulate an integrated approach to planning, investment, and operations;
- Develop an open process to promote utility/stakeholder relations, enable third parties the opportunity to provide cost-effective market solutions to identified energy needs, drive member value related to the distribution system, and embrace innovation where cost-effective;
- Specify the expected or potential near-term effects of increased distributed generation penetration on the ability to serve customers, with specific reference to each type of distributed generation and its grid interface;
- Identify the need for system upgrades regardless of distributed generation potential;
- Perform a technical assessment and description of WEC's T&D system with respect to changes from grid modernization (distributed generation, energy efficiency, new plug loads such as EVs and CCHPs);
- Plan for circuit based analysis;
- Identify the level of distributed generation capacity on WEC systems on a given distribution circuit that could be integrated without additional upgrades or expansions;
- Identify system efficiencies (lowering of distribution losses, deferral/avoidance of investments, and rebuild work);
- Develop a plan that will take into account changing load shapes, increased distributed generation, and the effect that these factors will have on the existing system and any planned capital expenditures;
- Identify locations, based on proposed capital plans, where distributed generation has the potential to resolve or mitigate forecasted system requirements that would otherwise necessitate traditional infrastructure investments for system expansion/upgrade and/or maintenance;
- Include effects of storage and behind the meter generation on WEC's system;

- Identify specific system needs allowing stakeholders and market participants to identify opportunities;
- Identify collaboration efforts with other Vermont utilities, VELCO, and the Vermont System Planning Committee (VSPC) process;
- Identify specific areas in WEC's system where there is an impending or foreseeable delivery infrastructure upgrade need;
- Identify specific areas where there is no projected delivery infrastructure need for years to come, and hence the infrastructure avoidance value of distributed generation is likely to be lower or insignificant in the short-term;
- Identify and distinguish operational needs during normal operations and during outage events or other periods of system stress (low voltage condition, near thermal limitations, etc.) and plans to implement reliability enhancing protocols like fault location, isolation, and service restoration;
- Develop information on optimal locations and levels of storage facilities, either on the system or behind the customer's meter, as storage technologies integrated into grid architecture may potentially be used for reliability and to support the deployment of other distributed resources;
- Prepare system data on a substation basis: hourly load curves, voltage, power quality, reliability;
- Prepare individual feeder system data (load data, voltage, power quality, reliability, etc.) for feeders within areas that distributed generation is expected to have more value;
- Consider and propose demonstration projects, as appropriate, in order to continually improve, refine, and otherwise drive toward the state's energy objectives;
- Develop maps and other means to identify geographically where distributed generation is best suited;
- Explore other utility and public sources related to solar mapping and use early research to help guide analysis.

WEC's T&D planning efforts will be an evolving and dynamic process. As we learn more about our system and perform more detailed studies relative to distributed generation and grid modernization, we will adapt our efforts and report findings through the IRP process. Hence, this is an ongoing and iterative process.

## 5.2. WEC Construction Work Plan

WEC receives financing from the Rural Utility Service (RUS) for its electrical system improvements. One of the requirements for RUS borrowers is the periodic development of a

Construction Work Plan (CWP). The CWP is developed and written in accordance with the RUS Bulletin 1724D-101B guidelines.

WEC's current CWP, dated June 2014 and covering the period from 2014 – 2017, is still active with RUS approved projects scheduled into the fourth quarter of 2017. In advance of completing the current CWP, WEC is developing a new plan that will cover the period from early 2017 through 2020. The completion of WEC's current CWP is on schedule and expected to continue to the end of 2017.

The requirements of the CWP are laid out by RUS and are summarized as follows:

> The Construction Work Plan process is used to determine and document a borrower's 2 to 4 year construction needs that are the most feasible, environmentally acceptable and economical. New construction is periodically required in order to provide and maintain adequate and reliable electric service to all of a system's new and existing members. The CWP should include all recommended electric plant facilities regardless of the financing source (general funds, RUS, or all other lenders). A CWP is a valuable reference for the preparation of annual construction budgets and schedules. The CWP report is also used as an engineering support document for a loan application to finance a proposed construction program. As such, the CWP is used as a means to inform RUS and receive RUS's approval of proposed new construction items (from RUS Bulletin 174D-101B, page 3)

WEC's CWP provides a detailed work plan for improvements to maintain the reliability and efficiency of the electric distribution system. It is also a tool that is used by WEC to manage projects and a guide to:

- Determine the most practical and economical means of serving future loads while maintaining high quality service to members;
- Outline anticipated system changes in terms of major facilities, demand levels and associated costs; and
- Help forecast future system costs for financial planning and decision-making.

A CWP provides guidance for developing the existing system toward the capacity level which will be required at the end of the planning period, through construction of new facilities and expansion or replacement of existing facility at appropriate times. The plan incorporates critical elements that need to be addressed to provide safe, reliable, and efficient electric service at a reasonable costs.

## 5.3. WEC T&D System Evaluation

The Comprehensive Energy Plan provides guidance via the IRP addendum relative to utility planning for transmission and distribution system improvements. The addendum states:

> Each electric utility should plan and conduct a comprehensive study evaluating options for improving transmission and distribution (T&D) system efficiency and reliability. Based on the findings of that study, it should then implement a program to bring its T&D system to the level of electrical efficiency that is optimal on a present value of life cycle cost basis within a reasonable period of time. These studies and action plans should be reviewed and updated at reasonable intervals. Finally, each utility should implement a program, as part of its IRP, to maintain T&D efficiency improvements on an ongoing basis.[37]

WEC worked with the DPS engineering staff in the development of its CWP. As stated above, WEC is preparing to begin work on a new plan (2017 through 2020) and WEC staff will meet with the DPS to review the approach and outline. WEC has also reviewed the IRP guidelines, which call for the following measures:

> Each utility should evaluate individual T&D circuits to identify the optimum economic and engineering configuration for each circuit, while meeting appropriate reliability and safety criteria. The IRP should contain a detailed description of how and when the utility will carry out these evaluations.
>
> Decisions regarding some facilities may affect more than one utility. In such instances, utilities should work together so that their evaluations reflect not only their individual interests, but also the interests of ratepayers generally.
>
> The standard for establishing optimum T&D system configurations and for selecting transmission and distribution equipment is the net present value of life cycle cost. This life cycle cost should be evaluated on both a societal and utility/ratepayer basis. This standard requires consideration of a project's capital costs and life cycle operating costs, as well as benefits resulting from the construction of enhanced system configurations and the installation of energy efficient T&D components. These benefits include avoided operation and maintenance costs, and avoided energy and capacity costs.

[37] 2016 CEP Appendix B: Guideline for Integrated Resource Plans and 202(f) Determination Requests, p 19

Avoided energy costs include the direct costs for energy, the costs for energy consumed as line losses, and T&D delivery costs. Avoided capacity costs include fixed costs and capacity charges for power including on peak line losses, fixed costs and capacity charges for T&D, the cost of Capability Responsibility reserve obligations, the deferral of T&D investments. Other benefits of T&D system efficiency include reduced environmental externalities and reduced market prices due to reduced demand for energy and capacity.

Evaluations should identify and compare all technically feasible investments to improve system reliability and efficiency. At a minimum, evaluations should include (and assess the economics and technical feasibility where appropriate) the following measures:

1) The utility's power factor goal(s), the basis for the goal(s), the current power factor of the system, how the utility measures power factor, and any plans for power factor correction;

2) Distribution circuit configuration, phase balancing, voltage upgrades where appropriate, and opportunities for feeder back-up;

3) Sub-transmission and distribution system protection practices and philosophies;

4) The utility's planned or existing "smart grid" initiatives such as advanced metering infrastructure, SCADA, or distribution automation (see Section 4.6);

5) Re-conductor lines with lower loss conductors;

6) Replacement of conventional transformers with higher efficiency transformers;

7) The utility's distribution voltage settings (on a 120 V base), and whether the utility employs, or plans to employ, conservation voltage regulation or volt/VAR optimization;

8) Implementation of a distribution transformer load management (DTLM) or similar program (see Section 4.2);

9) A list of the locations of all substations that fall within the 100 and 500 year flood plains, and a plan for protection or relocation of these facilities;

10) A discussion of whether the utility has an underground Damage Prevention Plan (DPP), or plans to develop and implement a DPP, if none exists;

11) The location criteria and extent of the use of animal guards;

12) The location criteria and extent of the use of fault indicators, or the plans to install fault indicators, or a discussion as to why fault indicators are not applicable to the specific system;

13) A pole inspection program, the plans to implement a pole inspection program, or a discussion as to why a pole inspection program is not appropriate to the specific utility;

14) The impact of distributed generation on system stability.

The requirements of the comprehensive Construction Work Plan required by RUS parallels the requirements outlined in 1 through 14 above. The proposed CWP that is currently being developed will be expanded to include the 14 items requested in the 2016 CEP.

## 5.4. Analysis of WEC System

The existing WEC distribution system has approximately 1,263 miles of overhead distribution line and 22 miles of underground primary distribution for a total of 1,285 miles. The distribution system operates at 12.47/7.2 kV.

The distribution system consists of eight substations and one primary metering point. Table 5-1 provides a list of the substations/circuits and the approximate length of primary overhead and underground on each circuit.

Table 5-1. Summary WEC Substations and Circuits

| Table 3<br>Primary Line Lengths by Substation/Feeder | | | | | |
|---|---|---|---|---|---|
| | | | Approx. Length (Mi.) | | |
| Substation | Sub No. | Circuit | Overhead | Underground | Meters |
| East Montpelier | 1 | 1 | 35.5 | 0.8 | 262 |
| | | 2 | 73.8 | 0.9 | 830 |
| | | 3 | 49.7 | 1.5 | 582 |
| Jones Brook MP* | 2 | 1 | 6.9 | 0.0 | 79 |
| Mt. Knox | 3 | 1 | 69.9 | 0.0 | 579 |
| | | 2 | 133.7 | 0.6 | 1,284 |
| West Danville | 4 | 1 | 38.4 | 0.5 | 446 |
| South Walden | 5 | 1 | 51.3 | 0.0 | 427 |
| | | 2 | 43.7 | 0.0 | 462 |
| | | 3 | 36.3 | 0.1 | 281 |
| Jackson Corners | 8 | 1 | 40.4 | 0.0 | 409 |
| | | 2 | 52.3 | 0.3 | 321 |
| | | 3 | 107.9 | 1.3 | 1,253 |
| Moretown | 9 | 1 | 42.1 | 0.3 | 466 |
| | | 2 | 16.3 | 1.0 | 154 |
| | | 3 | 50.9 | 1.6 | 781 |
| Maple Corners | 10 | 1 | 28.1 | 0.4 | 279 |
| | | 2 | 49.8 | 0.1 | 564 |
| North Tunbridge | 11 | 1 | 82.4 | 0.8 | 687 |
| | | 2 | 27.1 | 0.1 | 230 |
| | | 3 | 34.64 | 0.0 | 257 |
| Totals | 8 | 21 | 1,071.14 | 10.3 | 10,633 |
| *metering point only | | | | | |

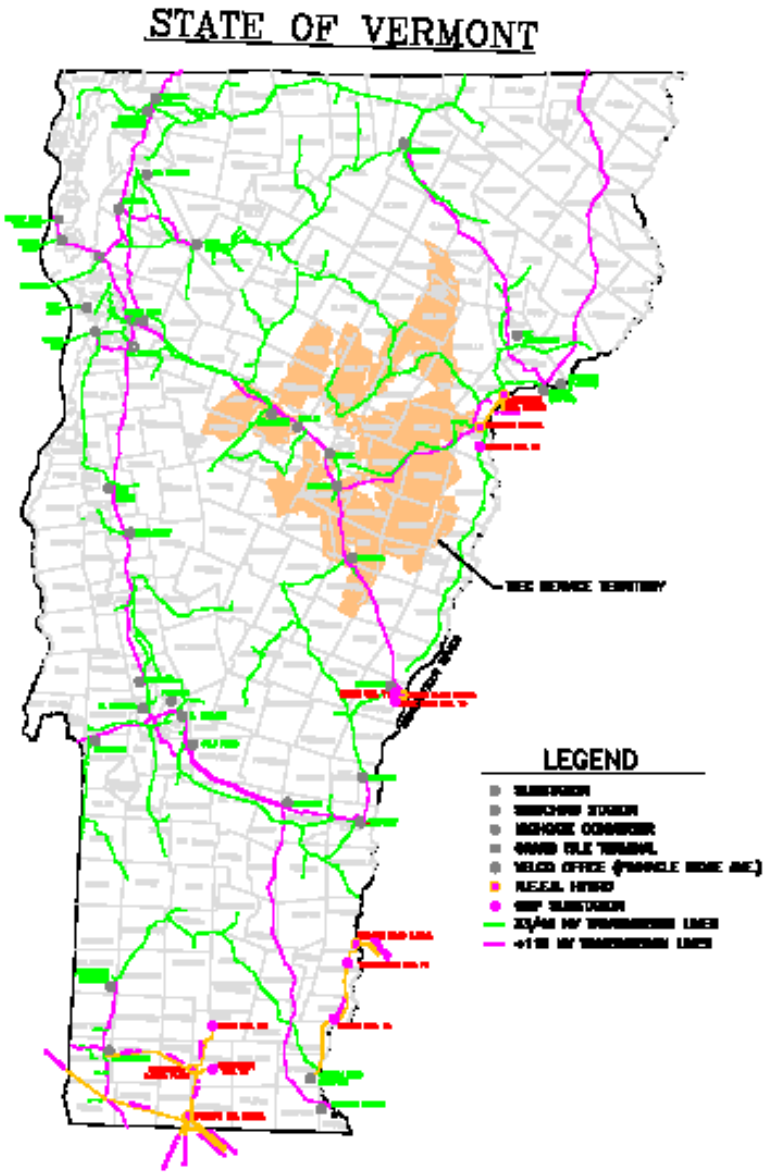
The primary conductor size on the system ranges from 3/12 copperweld to 4/0 aluminum on the overhead portion of the line and 1/0 aluminum cable on the primary underground line, which accounts for approximately .9% of the total system.

Five of the eight substations were originally built as wood pole structures with timber crossarms, varying in age. Four substations, Moretown, South Walden, Maple Corners, and East Montpelier, have been completely rebuilt with modern metal frame construction and increased clearances to meet present requirements. West Danville Substation, while a wood pole structure, was rebuilt in 1986 while major equipment was replaced in 2002, and is therefore in good condition.

## Transmission Facilities

The majority of the power distributed to WEC's customers is generated outside of WEC's service area. Therefore, WEC depends on transmission facilities owned by VELCO, GMP and ISO-NE to transmit power to their electrical facilities. The Vermont transmission facilities are shown in the following map of Vermont relative to WEC's service territory.

Figure 5-1. Comparison Forecasts



WEC owns approximately 15.7 miles of 34.5 kV transmission line that completes the link between the transmission facilities owned by others and WEC's substations. These lines interconnect and serve the Jackson Corners, Maple Corners, and South Walden substations. WEC owns an additional 2.6 miles of 46 kV transmission line that serves the North Tunbridge substation and 7.2 miles of 48kV line that connects the Coventry Landfill Gas Plant to the VELCO Irasburg Substation. The specific distances of the transmission line taps are detailed in Table 5-2.

Table 5-2. Summary WEC Transmission Lines

| Table 4<br>WEC Owned Transmission Lines | | |
|---|---|---|
| Substation | Voltage | Length (Miles) |
| Jackson Corners | 34.5 | 4.4 |
| Maple Corners | 34.5 | 9.0 |
| North Tunbridge | 46.0 | 2.6 |
| South Walden | 34.5 | 2.3 |
| Coventry | 48.0 | 7.2 |
| Totals | | 25.5 |

Planning criteria are used to establish the rules for assessing WEC's distribution system performance. The criteria include voltage limits, conductor thermal loading limits, and equipment thermal loading limits.

The planning criteria cover WEC's 34.5 kV sub-transmission system and distribution system that ranges in phase to phase voltage from 12.47 to 34.5 kV. The following planning criteria were utilized in preparing this CWP:

- Distribution lines will be limited to 300 amps or the conductor's normal rating, whichever is lower;

- Distribution line voltage will be held between 115 and 125 volts with a maximum swing of six volts between peak and off peak loading. Tap changer compensation will be used where possible to limit daily voltage swings;

- A distribution line will be limited to two levels of line regulation beyond the substation bus;

- Substation transformer and regulator loads will be limited to their nameplate rating;

- The distribution system losses will be evaluated on a regular basis and all cost-effective loss reduction projects will be implemented. Re-conductoring, adding phases, adding capacitors, and new metering points and substations are examples of projects to be considered;

- The most important consideration in developing the work plan projects was condition of wires and poles. After the pole inspection program was completed, the lines with a significant number of deteriorated poles were identified and projects were proposed to replace these lines. In addition, the condition and size of the primary conductor was taken into consideration, with "Amerductor" and Copperweld wire being considered the priority.

The analysis of the current system was significantly simplified by the fact that a Long Range Plan was completed in 2011. The CWP builds on the work completed in this study:

- East Montpelier #1/Maple Corners #10

The East Montpelier #1 and Maple Corners #10 model was run at a 2016 load level of 3,733 kW with base losses of 105 kW. There were no line sections below 116 volts.

- Jones Brook #2

The Jones Brook Metering Point was run at a 2016 load level of 122 kW. No problems were encountered. The 2016 voltage at the line end was 118.5 volts.

- Mt. Knox #3

The Mt. Knox #3 model was run at a 2016 load level of 2420 kW, with losses of 131 kW. No problems are anticipated through 2016. The lowest expected end-of-line voltage was 119 volts.

- West Danville #4

The West Danville model was run at a 2016 load of 531 kW. There was no voltage or loading issues in the model. The base line losses were 8 kW.

- South Walden #5

The South Walden model was run at a 2016 load of 1,681 kW, with line losses of 72 kW. A low voltage problem was found in the North Walden area. A regulator installation on Noyestar Road and the transfer of Coles Pond Road to the Noyestar Road feed will solve this problem.

Feeder #1 is a single phase line that is running 72 amps. Any pole replacements on this line section should take into consideration the long range plan to rebuild this as a three phase line.

- Jackson Corners #8

The Jackson Corners model was run at a 2016 load of 3,362 kW with 126 kW in losses. There is a low voltage problem on Berlin Pond Road when the solar project is not on line. A regulator on Berlin Pond Road will solve this problem.

A 3.9 mile section of the South Circuit main line is proposed to be reconductored with 4/0 AAAC wire. The poles on this line are original 1940's vintage and a significant number are condemned. The loss reduction from this project is 6 kW.

- Moretown #9

The Moretown model was run at a 2016 load level of 2,476 kW, with losses of 123 kW. The voltage on B Phase along Route 100, where the main line connects, indicated a projected voltage of 114.3 volts. The capacitor on Upper Crossett Hill Road will need to be increased to 100 KVAR will resolve the problem.

- North Tunbridge #11

The North Tunbridge model was run at a 2016 load level of 1,567 kW with 87 kW of losses. Feeders #2 and #3 are both single phase lines and running at approximately 55 amps. The lowest expected voltage, after completion of the proposed projects, is 121 volts. Any pole replacements on the main lines of these circuits should take into consideration the long range plan to add phases to these feeders.

Table 5-3. Substation Equipment Summary

| Table 6 | | | | | | |
|---|---|---|---|---|---|---|
| **Age of Substation Equipment Summary** | | | | | | |
| Substation | Year Constructed | Year of Transformer Installation | Year of Regulator Installation | Year of Recloser Installation | Year of Construction | Condition of Poles |
| East Montpelier | 2011 | 2011 | 2011 | 2011 | 2011 | Steel |
| Jackson Corners | 1968 | 1991 | 2000 | 2010 | 1968 | Good |
| | | 1991 | 2000 | 2010 | | |
| | | | 2000 | 2010 | | |
| Maple Corners | 2006 | 2006 | 2006 | 2006 | 2006 | n/a (steel) |
| Moretown | 2001 | 2000 | 2000 | 2000 | 2001 | n/a (steel) |
| | | | | 2010 | | |
| Mt. Knox | 1971 | 1975 | 2000 | 2006 | 1970 | Fair/Good |
| | | 1975 | 2000 | 2006 | | |
| | | 2000 | 2000 | | | |
| North Tunbridge | 1975 | 1997 | 2008 | 2010 | 1975 | Good |
| | | 2003 | 2008 | 2010 | | |
| | | 2003 | 2008 | 2010 | | |
| South Walden | 2003 | 2003 | 2003 | 2003 | 2003 | Steel |
| | | | | 2010 | | |
| West Danville | 1986 | 2002 | 2002 | 2002 | 1986 | Good |

Substation Transformer Capacity: The capacity of each substation was reviewed as part of the study. There are no substations that are currently experiencing transformer capacity restraints.

The projected load for each of the substations based on the LRP load forecast is shown in Table 5-4. The only substation projected nearing its transformer capacity is Jackson Corners.

Table 5-4. Peak Load Summary

| Table 7 | | | | | |
|---|---|---|---|---|---|
| Peak Load Data | | | | Projected Peak | |
| Substation | Substation kVA | 2012 Peak Demand | Percent Capacity | 2015 | 2021 |
| East Montpelier* | 5000 | 3627 | 72.5% | 3799 | 4033 |
| Jones Brook | n/a | 164 | 0.0% | 172 | 183 |
| Mt Knox | 3750 | 2412 | 64.0% | 3020 | 3205 |
| West Danville | 1500 | 522 | 35.0% | 605 | 643 |
| South Walden | 2500 | 1624 | 65.0% | 1623 | 1723 |
| Jackson Corners | 3750 | 3254 | 87.0% | 3140 | 3334 |
| Moretown | 3750 | 2373 | 63.0% | 2656 | 2819 |
| Maple Corners* | 2500 | 1100 | 44.0% | 1156 | 1227 |
| North Tunbridge | 3750 | 1500 | 40.0% | 1774 | 1883 |
| Total System | 26500 | 16576 | 62.0% | 17945 | 19050 |
| * The loads are on one metering point | | | | | |

Voltage Levels and Thermal Overloads: The existing WEC system was modeled in MilSoft Engineering Software at the 2016 load levels to determine if there were any existing deficiencies on the system. The load analysis identified three areas with significant voltage problems which were addressed above. There were not any areas where equipment was near its thermal overload capacity.

Substation Location with Respect to Flood Plains: In 2013, WEC contracted with Dubois and King to complete a study of the location of substations with respect to 100 year flooding. The study found that only one of WEC's substations is within a flood zone. The Maple Corners Substation could experience inundation of various levels, based on the actual failure mode and weather conditions during a dam failure at Curtis Pond. The level of inundation is not expected to create a problem with the operation of the substation but could affect access to the substation while the flood waters are present.

**Summary**

This section of the report summarizes the recommended projects that are included in this 2014-2017 CWP. The projects are separated by substation in this section. Projects are listed in categories that include system improvements, capacitor installations, equipment additions/replacements and system reliability.

**Projects Listed by Substation**

East Montpelier #1

| Project Description | Miles | Cost | Phases |
|---|---|---|---|
| 301-32 Reconductor #6/8 CWC to 1/0 AAAC | 1.10 | $86,852 | 1 |
| 301-33 Reconductor #3/12 CWC to 1/0 AAAC | 2.30 | $210,825 | 1 |
| 301-34 Replace primary underground | 0.05 | $9,000 | 1 |
| 301-35 Replace primary underground | 0.30 | $37,500 | 1 |
| 301-36 Replace primary underground | 0.56 | $104,475 | 1 |

Overall, 3.45 miles of line will be rehabilitated at an estimated cost of $306,676.
An additional .86 miles of cable will be replaced at an estimated cost of $141,975.

Jones Brook Metering Point #2

There are no projects scheduled for Jones Brook #2.

Mt. Knox #3

| Project Description | Miles | Cost | Phases |
|---|---|---|---|
| 303-41 Reconductor #4 Cu to 1/0 AAAC | 1.1 | $102,550 | 1 |

Overall, 1.1 miles of line will be rehabilitated for an estimated cost of $102,550.

West Danville #4

| Project Description | Miles | Cost | Phases |
|---|---|---|---|
| 304-16 Reconductor #3/12 CWLD to 1/0 AAAC | 1.1 | $106,027 | 1 |
| 334-17 Reconductor #4 ACSR to 1/0 AAAC | 1.4 | $131,700 | 1 |

Overall, 2.5 miles of line will be rehabilitated for an estimated cost of $237,727.

South Walden #5

| Project Description | Miles | Cost | Phases |
|---|---|---|---|
| 305-29 Reconductor #3/12 CWLD 1/0 AAAC | 0.38 | $35,120 | 1 |
| 305-30 Reconductor #6/8 CWC to 1/0 AAAC | 0.50 | $45,656 | 1 |
| 305-31 Reconductor #3/12 SCG to 1/0 AAAC | 0.75 | $68,484 | 1 |
| 305-32 Reconductor #6/8 CWC to 1/0 AAAC | 1.60 | $149,260 | 1 |
| 305-33 Reconductor #6/8 CWC to 1/0 AAAC | 2.40 | $221,432 | 1 |

Overall, 5.63 miles of line will be rehabilitated at an estimated cost of $519,952.

Project 604 will install a regulator on Noyestar Road in Walden in 2014 to reduce voltage drop. The estimated cost is $9,500.

Project 1002 will replace the transmission switch at the South Walden Tap of the 3319 line. The estimated cost is $12,500.

Jackson Corners #8

| Project Description | Miles | Cost | Phases |
|---|---|---|---|
| 308-42 Reconductor #3/12 CWC to 1/0 AAAC | 2.20 | $205,540 | 1 |
| 308-43 Reconductor #3/12 CWC to 1/0 AAAC | 0.70 | $ 63,918 | 1 |
| 308-44 Reconductor #2 AAAC to CWC to 1/0 AAAC | 0.40 | $38,632 | 1 |
| 308-45 Reconductor # 1/0 ACSR to 1/0 AAAC | 0.45 | $52,680 | 1 |
| 308-46 Reconductor #2 ACSR to 4/0 AAAC | 0.57 | $288,028 | 3 |
| 308-47 Reconductor #2 ACSR to 4/0 AAAC | 1.90 | $175,216 | 3 |
| 308-48 Reconductor #2 ACSR to 4/0 AAAC | 1.20 | $296,881 | 3 |
| 308-49 Reconductor #2 ACSR to 4/0 AAAC | 0.60 | $136,231 | 3 |
| 308-50 Rebuild underground | 0.40 | $52,500 | 1 |
| 308-51 Add a phase along Route 302. | 0.90 | $80,000 | 1 |
| 308-52 Reconductor #6 SCG to 1/0 AAAC | 0.40 | $21,072 | 1 |

Overall, 9.72 miles of line will be rehabilitated at an estimated cost of $1,410,698.

Project 1001 will replace porcelain insulators on the Graniteville-Jackson Corners 34.5 kV line. The estimated cost is $110,000.

Moretown #9

Project 500 Install single phase electronic recloser in the Moretown substation serving feeder 1 which will replace the hydraulic recloser located on the line.

Project 605 will upgrade the capacitor on Upper Crossett Hill Road in 2014 to reduce voltage drop. The estimated cost is $2,400.

Maple Corners #10

| Project Description | Miles | Cost | Phases |
|---|---|---|---|
| 310-34 Replace primary underground | 0.34 | $54,000 | 1 |
| 310-35 Replace primary underground | 0.22 | $36,300 | 1 |

Overall, .56 miles of cable will be rehabilitated at an estimated cost of $90,300.

North Tunbridge #11

| Project Description | Miles | Cost | Phases |
|---|---|---|---|
| 311-25 Reconductor #4 ACSR with 1/0 AAAC | 0.40 | $35,120 | |
| 311-32 Reconductor #6/8 CWC to 1/0 AAAC | 1.90 | $175,600 | 1 |
| 311-33 Reconductor #3/12 CWC with 1/0 AAAC | 1.60 | $145,291 | 1 |
| 311-34 Reconductor #3/12 CWC with 1/0 AAAC | 1.30 | $120,725 | 1 |
| 311-35 Reconductor #3/12 CWC with 1/0 AAAC | 1.80 | $164,449 | 1 |
| 311-36 Reconductor #3/12 CWC with 1/0 AAAC | 1.00 | $93,770 | 1 |
| 311-37 Reconductor #3/12 CWC with 1/0 AAAC | 0.90 | $79,020 | 1 |
| 311-38 Reconductor #4 ACSR with 1/0 AAAC | 0.50 | $43,900 | 1 |
| 311-39 Reconductor #4 ACSR with 1/0 AAAC | 0.20 | $15,189 | 1 |
| 311-40 Reconductor #4 ACSR with 1/0 AAAC | 0.75 | $68,484 | 1 |
| 311-41 Reconductor #6/8 CWC with 1/0 AAAC | 1.10 | $102,638 | 1 |
| 311-42 Reconductor #6/8 CWC with 1/0 AAAC | 1.80 | $166,996 | 1 |

Overall, 13.25 miles of line will be rehabilitated at an estimated cost of $1,211,182.

1002 Replace transmission switch $18,500

Smart Grid Projects

AMI Meters system-wide as needed $101,448
AMI Repeaters PLC signal repeaters $72,377

WEC has a complete CWP for 2014-2017 filed as part of its IRP filing. As noted this CWP was reviewed by the DPS as an addendum to the 2014 IRP. We have included a one page summary of the status of projects outlined in the current CWP in the Appendix section of the IRP. For a detailed analysis of the WEC system and summary of planned projects please see the CWP in the Appendix. Included in the CWP are many other topics as required by the IRP guidelines and RUS. These additional items are listed below:

- Analysis of Current System
- Current Review Rating Summary (RUS Form 300)
- Sectionalizing & Fuse Coordination Studies
- Historical and Projected System Data
- Load Current Measurements
- Voltage Measurements
- System Outages and Reliability
- Demand and Energy Losses
- Pole Replacement and Pole Inspection/Treatment
- Small/Aging Conductor
- Vegetation Management
- Environmentally Sensitive Areas
- Energy Efficiency Services
- Other Operational Issues

# 6. Action Plan

## 6.1. Overview of Supply Plan and Action Items

As noted in the 2016 Comprehensive Energy Plan, utilities should use the IRP process to address questions that are the most relevant to the utility at the time of the IRP. WEC met with the Department in advance of the filing to discuss key issues and questions it desired to address in this filing. WEC and the Department agreed that since WEC is not making large or longer term power supply decisions for the next five years, its IRP will be used to provide an update to its power supply situation while focusing more on other areas, such as the Act 56 Renewable Energy standard, Act 99 net metering, impacts of distributed generation to the T&D systems, and its capacity market needs. In this IRP filing, WEC will provide updates to the major elements of its IRP and will focus on issues germane to it in the next several years.

WEC sees its largest question for the future not in large power supply and resources decisions other than capacity, but rather in costs and benefits and the impacts of changes to demand and grid modernization. Increased deployment of distributed generation are lowering WEC's energy revenues and peaks while cost pressures from transmission and capacity markets are driving costs up. To be sustainable and serve our members' needs in an industry moving toward rapid deployment of smaller distributed sources of generation and increased uncertainty of load, WEC looks to rate design and storage as a potential means of which to keep rates and bills to members stable while it also attempts to minimize subsidization between customer classes.

Lowering electric rates and bills, while maintaining environmental considerations, requires WEC to look at lower peak use at the time of the ISO-NE peak. In addition, flattening WEC's load shape and minimizing seasonable fluctuations where possible can help manage costs. WEC will also look at exploring ways to reduce its regional load levels while maintaining revenues (such as making more use of load reducers from internal generation sources) as a way to keep rate pressures in check. Rate design and analysis of WEC's cost of service may also help stabilize member bills and address a current dependence on obtaining revenue from the variable component or kWh sales.

The IRP simulations are intended to identify key issues WEC should monitor and assist WEC in charting a course towards an optimal strategic resource mix. The simulations also inform WEC how its existing supply commitments perform over time and under various

market conditions. Since WEC does not at this time have a need to make large or long range resource decisions other than capacity, the IRP modeling is meant to serve as a means to identify how WEC's portfolio changes under varying market conditions. This allows WEC to plan for uncertainty and attempt to hedge risk in the day-to-day management of its portfolio. WEC has identified through this effort key drivers that will impact its members, and its action plan is framed to respond to these key variables and risks. While WEC is not making new resource decisions there is still the need to monitor and adjust WEC's decision-making to insulate it against price volatility and unexpected events.

The value of the simulated portfolio analysis is that it allows WEC to identify key variables and cost impacts from those variables to WEC long-term. WEC is better positioned to understand the potential cost volatility of its portfolio if markets change. Many factors will affect the management of WEC's resource portfolio over the 20-year planning horizon. WEC's action plans will respond to the uncertainties inherent in the management of its existing portfolio.

The exact portfolio in any given year will be dependent upon a number of variables analyzed in the IRP, plus variables that were not analyzed including (in no particular order):

- Impact on WEC's Mortgage Covenants including Operating Times Interest Earned Ratio (OTIER), TIER, and Debt Coverage;
- Impact on WEC rates;
- Capital requirements;
- WEC's access to capital;
- Pursuit of renewable power sources;
- Externalities;
- Balance of short-term costs versus long-term savings and vice-versa;
- Local economic impact;
- Supplier credit risk; and
- Credit assurance required of WEC.

The next step is to describe how WEC used the resource modeling to determine its action plan and decision-making. As noted above, the modeling output identifies and measures various market impacts and risks. From the modeling results, WEC staff spent time analyzing

tornado charts (see Figure 2-11), reviewing resource costs (see Table 2-11), and developing a detailed understanding of other key metrics provided from the analysis. The model output was very informative and tells WEC what its biggest market risks are from a cost and volatility perspective. Once WEC assembled the metrics and identified risks, staff then drafted plausible action plans.

Afterwards, WEC staff presented information and the draft action plans to WEC's decision-makers (WEC Board of Directors and Finance Account and Power Planning (FAPP) Committee, which is a subset of the full Board). The WEC FAPP committee is tasked with developing a more detailed understanding of power supply and financial impacts and subject matter. The FAPP committee acts as a study, screening, and test group and it informs the full board about financial and power supply related issues. In this role, it allows WEC to analyze and make decisions regarding power and operations in a more efficient manner.

The next step involved the presentation of the working draft and model results to the full WEC Board of Directors. At a WEC Board meeting in June, WEC staff presented a final report and sought approval for the development of the final action plan and IRP report.

This process can be described as a culmination of meetings and an iterative process to arrive at an end result. The decision-making blends a highly analytic exercise through the IRP modeling with qualitative reactions and policy level assessments from WEC's nine member elected Board of Directors. This process makes use of data, but also relies heavily on public discussion, open dialogue, and debate, rather than pure analysis.

This is standard procedure for any item that comes before the WEC FAPP committee or the WEC Board. For example, WEC identifies in IRP Section 2.7 several qualitative criteria that Board members may use to guide their decision-making. These include not only cost but diversity, risk, uncertainty, and environmental impacts. The FAPP committee and WEC Board use their judgment in weighing each of the criteria described in Section 2.7 to reach their conclusions relative to the IRP. Through meetings and discussions, WEC decision-makers vet data, share thoughts, exchange opinions, and ultimately reach conclusions as a group. These conclusions ultimately informed a final set of decisions and an action plan. WEC believes the synergy between the quantitative model output and the feedback from the WEC Board as policymakers is effective in driving WECs action plan and decision-making.

In the end, the vote to approve and support the WEC IRP and report was a vote of the nine member elected Board of Directors.

Through the analyses summarized in the prior sections of this IRP, WEC has developed action plans that focus on various activities designed to further refine and implement the resources, projects, and/or strategies identified as having potential benefits. The various action plan items are defined below.

## 6.2. Ongoing IRP Maintenance and Evaluation

WEC plans to supplement its IRP with further analysis, planning, and initiatives intended to minimize adverse impacts and risks:

- Affordability: In light of flat to declining load and rising costs, WEC faces rate pressure affecting affordability for its member owners. WEC will explore cost mitigation measures throughout WEC's operation. WEC will also look at alternative rate structures and means to build load that will offset costs for all members. WEC will explore Time of Use rates and load control efforts that will have a meaningful impact. WEC will examine ways to respond to changing load shape with focus on peak reductions that drive costs (transmission, capacity, etc). WEC will examine load filling mechanisms such as converting energy uses away from fossil fuels in transportation and heating sectors toward electric use where it is cost-effective to the member. WEC will look at cost of service designs and rate structures to equitably share costs among members. WEC will explore and identify real world impacts of legislative mandates that increase cost to WEC members and perform quantitative analysis to help inform policy makers of the impacts to WEC and its members (2017-2020);
- RECs: The analysis identified the most significant driver to the Status Quo case is the price of RECs. Therefore, this key variable deserves significant attention relative to monitoring and analysis.

  In fact, in 2017 WEC is filing a 5.95% rate increase, which is in part driven by a fall in the price of RECs (this one item accounted for 3.04% increase to rates), while power costs due to transmission and FCM accounted for another 1.56%. As predicted in the 2014 analysis, a drop in REC prices can trigger significant cost pressure to WEC. This occurred in 2016, as REC prices have declined in the last two years from mid 40's to low 20s. WEC plans to monitor changes in REC markets and secure contracts to minimize financial risk and maximize revenues. Other efforts are noted below:

    - Examine rate structure. WEC is looking at its cost and rate structure to see if different approaches may lessen the impacts of falling RECs and increased power costs that are beyond WEC's control, such as the price of capacity in the

FCM market and cost of transmission. WEC will work with the Department and other stakeholders to explore mechanisms to recover costs from REC market changes outside of the traditional rate setting approach. Examples include a modified version of alternative regulation where deviations in power costs and REC revenues occur on the bill outside a companywide cost of service analysis;

- Continue to obtain reports and analysis to help inform WEC of market fundamentals (ongoing);
- Monitor legislative changes in all New England states (ongoing);
- Monitor legislative changes in Vermont and participate in framing future laws that may impact WEC (ongoing);
- Review REC portfolio approach (2017-2020);
- Participate in discussions regarding a Renewable Portfolio Standard in Vermont or other carbon legislation to which WEC is subject, and, if necessary, adjust WEC's portfolio to comply with state/federal law and/or PSB rules, and do so as cost effectively as possible (ongoing);
- Reduce WEC's exposure to the variability in the value of Renewable Energy Certificates by exploring contracts longer than 2-3 years but which are also balanced with tradeoffs to reduce risk (2017-2020):
  - Consider unit contingent sales;
  - Consider sales that transfer changes in market rules to buyer;
- WEC buys back sufficient lower cost RECs to green up its power mix by purchasing and retiring renewable energy credits to not only meet but exceed the 55% target set forth in 30 V.S.A. §8005 (d)(4). WEC's internal goal is to maintain a 100% renewable mix, which it achieved in 2014. It will continue to achieve this goal by purchasing low cost RECs and retaining RECs from some of its existing sources of power. WEC will green up its portfolio and lower its emissions mix by buying back RECs or retiring a portion of RECs from its existing mix of power resources. WEC plans to continue selling high value Class 1 RECs while buying back lower cost RECs in other RPS markets, thus achieving the goal of lower emissions while keeping costs low to its membership (2017-2020).

- Coventry: Based on the results of Portfolio 3, financial ramifications of a large reduction in generation from Coventry affects WEC due to increased energy market purchases and also a loss of REC sales. WEC has insulated a large amount of energy

market risk form loss of Coventry through the purchase of the HQUS contract and arrangement with VEC to take power back in the event of a sudden loss of the unit. WEC will explore other risk mitigation opportunities and related costs to protect it from a large reduction in generation:

  - Install new SRS systems (January 2017 - complete);
  - Monitor wells and production from landfill and work with landfill operator to maximize production (ongoing);
  - Work with O&M contractor to install refurbished engines (Q1 2017 - complete);
  - Perform emissions testing that will assure compliance with Title V air quality permit (ongoing);
  - Review existing insurance coverage (2017);
  - Assess value of shortening the length of REC contracts to insulate from lack of production in the event of a major failure at the plant, or lengthen contract durations and include unit contingent sales (2017-2020);
  - Seek contractual assurances and warranties relative to contracts with key players associated with the landfill and O&M of the facility (2017).

- Wrightsville: FERC relicensing and cost-benefit analysis. Based on what WEC currently knows, the FERC relicense needed for the hydro facility will be an expensive and complicated effort. An initial budget estimate received for the project shows costs could be as high as $300,000 to renew the license. This is a major investment in the project and it must be analyzed relative to the energy production and benefits created from the plant. WEC will perform a cost/benefit analysis to better understand the cost of license renewal relative to the benefits from the project (2017);
- FCM: Monitor WEC's capacity market position and ISO-NE prices through ISO-NE Market Committee participation. Continue to assess the ability to hedge capacity position long-term (ongoing):
  - Hedge against potential cost increases in the ISO New England capacity market by evaluating specific generating units or contracts for inclusion in the WEC resource mix especially in light of WEC's large open position relative to its capacity needs. Execute contracts if appropriate, particularly if the ISO-NE capacity markets become locational and higher Vermont zone prices become likely (2017-2020);
  - Minimize WEC's Forward Capacity Market expenses by identifying and evaluating ways to manage WEC's load at the time of ISO-NE's annual peak

(ongoing);

  - Monitor the ongoing developments of ISO-NE Forward Capacity Market rules and potential impacts on auction results. These potential impacts may affect the economics of capacity resource acquisitions (ongoing);
  - Continue to look for ways to lower WEC's capacity obligation such as through load reducers (similar to the treatment of the Wrightsville hydro station), distributed generation resources, demand side management (battery storage), and rate design (controllable loads and time of use rates) (ongoing).

- Transmission costs and RNS rates: Monitor ISO-NE Reliability and Transmission committee reports to assess changes and costs that drive RNS rates (ongoing):
  - Minimize WEC's exposure to ISO-NE transmission rates and maintain healthy revenues by cost effectively managing WEC's load at the time of the Vermont monthly peak in order to lower WEC's network load used in the computation of NEPOOL Open Access Transmission tariff and VELCO Transmission tariff charges (ongoing);
  - Continue to look for ways to lower WEC's transmission obligation, such as through load reducers (similar to status change used for Wrightsville) and distributed generation resources (ongoing);
  - Explore storage and demand shaping opportunities such as utility scale battery storage, member load control, and time of use rates (ongoing).
- HQ US PPA outlook: Continue to monitor and assess WEC's coverage ratio relative to contract terms of the HQUS PPA and arrangement with VEC until WEC has a need;
- Vermont reliability issues: Monitor and/or participate in discussions and analyses regarding the potential impacts on costs due to the building of new power plants and the retirement of large central plant power plants (such as Vermont Yankee) and other reliability projects through VELCO. WEC notes market prices for the Sheffield project have been depressed due to an oversupply of generation relative to load in this portion of Vermont. Continued build out of generation in this region is forcing renewable sources of power to be backed down. Additionally WEC is receiving lower credits for the power, which is adding to power costs (ongoing);
- ISO-NE issues: Monitor and/or participate in discussions and analyses regarding the ISO New England's Strategic Planning Initiative, which is designed to address concerns raised by ISO-NE staff regarding the generation mix in New England. The result of these could have a noticeable impact on wholesale power costs in New England. Investigate the use of financial hedging instruments to achieve the same goals as

outlined above (ongoing);

- Rates: Explore member interest in and value of a Time of Use (TOU) rate and other rate designs which may encourage new technologies and load growth in off-peak periods (2017-2020);
- CWP: Update CWP 2014-2017 consistent with RUS requirements and with addition of the following three elements which are identified in the Vermont Comprehensive Energy plan IRP Guidelines (2014):
    - Implement remaining projects from current CWP (2014-2017) (2017);
    - Implement a distribution transformer load management (DTLM) or similar program;
    - Create a list of the locations of all substations that fall within the 100 and 500 year flood plains, and a plan for protection or relocation of these facilities;
    - Create a current copy of the utility underground Damage Prevention Plan (DPP) (or provide a plan to develop and implement a DPP, if none exists).
- T&D: As a result of increased distributed generation, growing deployment of energy efficiency and new plug loads, WEC seeks to explore a T&D system analysis to assess a changing industry. WEC seeks to explore distributed generation and solar impacts on the grid through a self assessment and to answer the broad overarching question: How much distributed generation can the T&D system accommodate? WEC developed a scoping process that will allow it to specify the tools, process, and protocols to be developed in order to plan and operate a modern grid capable of dynamically managing distribution resources, supporting retail markets that coordinate significant distributed generation investment, and efficiently managing resources.

  Engineering and modeling efforts will be used to help inform how WEC plans, operates, and develops its system (where and which types of resources and equipment are best located on WEC's lines). WEC will also seek to balance distributed generation needs and grid modernization with the total cost of our system and ultimately with the impact to members' rates and bills. The scoping process will include:

    - Outline and provide overview of WEC's T&D system;
    - Develop and articulate an integrated approach to planning, investment, and operations;
    - Develop an open process to promote utility/stakeholder relations, enable third parties the opportunity to provide cost-effective market solutions to identified

energy needs, drive member value related to the distribution system, and embrace innovation where cost effective;

- Specify the expected or potential near-term effects of increased distributed generation penetration on the ability to serve members, with specific reference to each type of distributed generation and its grid interface;
- Identify need for system upgrades regardless of distributed generation potential;
- Perform a technical assessment and provide a description of WEC's T&D system with respect to changes from grid modernization (distributed generation, energy efficiency, new plug loads such as EVs and CCHPs);
- Plan for circuit based analysis;
- Identify the level of distributed generation capacity on WEC systems on a given distribution circuit that could be integrated without additional upgrades or expansions;
- Identify system efficiencies (lowering of distribution losses, deferral/avoidance of investments and rebuild work);
- Develop a load forecast that will lead to a more integrated planning process: changing load shapes, increased distributed generation, and the effect that these factors will have on the existing system and any planned capital expenditures;
- Identify locations based on proposed capital plans where distributed generation has the potential to resolve or mitigate forecasted system requirements that would otherwise necessitate traditional infrastructure investments—for system expansion/upgrade and/or maintenance, including effects of storage and behind the meter generation on WEC's system;
- Identify specific system needs allowing stakeholders and market participants to identify opportunities;
- Identify collaboration efforts with other VT DUs, VELCO, and the VSPC process;
- Identify specific areas in WEC system where there is an impending or foreseeable delivery infrastructure upgrade need, and where upgrades would have immediate benefit;
- Identify specific areas where there is no projected delivery infrastructure need for years to come and hence the infrastructure avoidance value of distributed generation is likely to be lower or insignificant in the short-term;
- Identify and distinguish operational needs during normal operations and during outage events or other periods of system stress (low voltage condition, near thermal limitations, etc.) and plans to implement reliability enhancing protocols such as fault location, isolation, and service restoration;
- Develop information on optimal locations and levels of storage facilities, either on

the system or behind the customer's meter, as storage technologies integrated into grid architecture may potentially be used for reliability and to support the deployment of other distributed resources;

  - Prepare system data on a substation basis: hourly load curves, voltage, power quality, reliability;
  - Prepare individual feeder system data (load data, voltage, power quality, reliability, etc.) for feeders within areas that distributed generation is expected to have more value;
  - Consider and propose demonstration projects as appropriate in order to continually improve, refine, and otherwise drive toward the state's energy objectives;
  - Develop maps and other means to identify geographically where distributed generation is best suited;
  - Explore other DU and public sources related to solar mapping efforts and use early research to help guide analysis.

WEC's T&D planning efforts will be an evolving and dynamic process. As we learn more about our system and perform more detailed studies relative to distributed generation and grid modernization, we will adapt our efforts and report findings through the IRP process. Distribution system planning must become more dynamic, and the methods applied must adapt to and account for the changing environment. New approaches to planning (including risk-management techniques and financial incentives) that predict rather than prescribe, and envision flexible rather than static distribution systems, can best reduce redundancy while increasing system reliability and affordability;

- Education: Use IRP to communicate to key stakeholders:
  - Post IRP on WEC website (2017);
  - Public hearings (2017);
  - Article in *Co-op Currents* (2017);
  - Area meetings (2017)
  - Educational material for WEC Board of Directors (ongoing);
- Update IRP in three years (2020).

## 6.3. Summary Wrap Up

For WEC, the IRP is a planning tool that helps guide resource decisions and charts a path for the future relative to power supply and other major capital investments. It is not intended to be a fixed and prescriptive outline of what WEC will do next, but rather a dynamic and evolving planning tool to help inform and guide WEC decision-making. The approach measures and analyzes how various resource options and plans are projected to perform in any number of future market environments, and on how well such plans satisfy WEC stakeholders' needs.

This report presents the results of an Integrated Resource Plan prepared by WEC. WEC has prepared the plan consistent with state rules, goals, and directives for an IRP. Consistent with Vermont's statutory policy, WEC uses the IRP as a key component in the development of its own strategic plan and understanding of its changing needs to delivery power consistent with its members' interests and policies of WEC.

WEC's goal is to develop a plan that supports the following:

- Provide energy to members as inexpensively as possible;
- Maintain financial strength and assure economic equity for its member-owners;
- Improve performance of WEC's distribution system for the benefit of members and provide access to local generation sources in WEC's service territory;
- Manage power supply, distribution, and transmission service at lowest cost, with consideration for environmental impacts and social concerns;
- Promote responsible environmental practices at WEC and assist members in doing so;
- Maintain strong member, community, and government relations in a changing environment;
- Maintain strong organizational, administrative, and communication services.

WEC's action plan endeavors to carry out balance among all WEC goals to deliver high quality and affordable electric service to its members. The portfolio WEC developed and the action steps reflect tradeoffs between various goals, costs, and meeting members' needs.

# 7. Appendix

**List of Documents:**

A. Summary Count of WEC Members by Town

B. Memorandum of Understanding between Washington Electric Co-op and the Vermont Department of Public Service 2014 IRP

C. 2015 WEC Residential Satisfaction Survey

D. WEC Net Metering Tariff filed January 17, 2017

E. WEC Tier III Annual Plan

F. 2016 System Reliability Report

G. Vegetation Plan

H. Docket 8714 Vermont Public Service Board Determination as Renewable Energy Provider Act 56

I. Construction Work Plan 2014-2017 & Project List Update