2017 Resource Report for

# Inc. Village of Orleans Electric Department

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Submitted to:

the Vermont Public Utility Commission
and
the Public Service Department of the State of Vermont

on
February 28, 2018

by
the Vermont Public Power Supply Authority

on behalf of
Inc. Village of Orleans Electric Department

in fulfillment of
Vermont Public Utility Commission Rule 5.206(b)

# 1) Executive Summary

The Inc. Village of Orleans Electric Department ("Orleans") submits the following report to the Vermont Public Utility Commission and the Public Service Department in compliance with Rule 5.206 (B), *Reporting Power Supply Transactions*. The information contained within this report summarizes Orleans's power supply needs and acquisition strategy. This report also summarizes resource transactions the utility expects to enter during the next five years.

Orleans relies on the Vermont Public Power Supply Authority (VPPSA) for its interactions with the Independent System Operator of New England (ISO-NE) and New England power markets. In addition to managing resources in the New England markets VPPSA explores new generation sources for its members.

# 2) Utility Information

In 2017, Orleans's total load requirement was 14,103,146 kWh; this includes RTLO in ISO markets plus known behind-the-meter generation. It reached a peak energy requirement from ISO-NE of 3,408 kW on December 28 at hour ending 9:00. Over the past several years, Orleans's load has fluctuated and is summarized in the following table.

| Year | Load Obligation in New England Market (kWh) | Percent Increase or Decrease |
|---|---|---|
| 2013* | 14,235,015 | |
| 2014* | 14,073,964 | -1.10% |
| 2015* | 14,015,492 | -0.40% |
| 2016 | 14,273,135 | 1.80% |
| 2017 | 14,103,146 | -1.20% |

*NOTE: 2013, 2014 & 2015 loads reflect ISO-NE RTLO; 2016 and 2017 reflect total load (RTLO plus known behind-the-meter generation)*

Orleans's energy needs are projected into the future by a regression model that uses past load trends, weather, economic forecasts and known customer changes. Updated load forecasts are completed regularly to refine Orleans's future energy need estimates. Below is a summary of Orleans's forecasted energy requirements from 2018

to 2022.

| Year | Total Load Obligation (kWh) | ISO-NE Settlement Load Obligation (kWh) | Percent Increase (Decrease) Total Load |
|---|---|---|---|
| 2018 | 14,133,420 | 14,118,727 | 0.20% |
| 2019 | 14,133,420 | 14,118,102 | 0.00% |
| 2020 | 14,137,325 | 14,119,710 | 0.00% |
| 2021 | 14,133,420 | 14,114,413 | 0.00% |
| 2022 | 14,133,420 | 14,113,391 | 0.00% |

# 3) Market Conditions and New England Wholesale Price of Electricity

*Wholesale Markets*

Since it was restructured in 1999 to implement competitive bidding for electrical power plants, the New England market has experienced increased volatility. Prior to 1999, power plants were self-dispatched based on actual cost and settled after the need for energy had been determined. In May 1999, the New England Wholesale Power Markets were restructured such that plants were centrally dispatched by the Independent System Operator of New England (ISO-NE) and settled based on the forecasted need for energy twelve hours in advance of the operating day. Generators were dispatched in economic order from lowest price to highest until the forecasted energy requirement was met. As a result, competitive market forces guided wholesale prices based on the ongoing balance between supply and demand.

In March 2003, Standard Market Design ("SMD") was implemented in the New England wholesale markets. Overseen by ISO-NE, this set of rules introduced various clearing points on the New England transmission system ("grid") with the goal of sending accurate price signals regarding supply and demand at different locations throughout Vermont and New England. Generators are given dispatch instructions one day in advance of the operating day (i.e "day-ahead") by matching bid prices (supply) with offers that represent the load needs of utilities (demand). A same-day (i.e. "real-

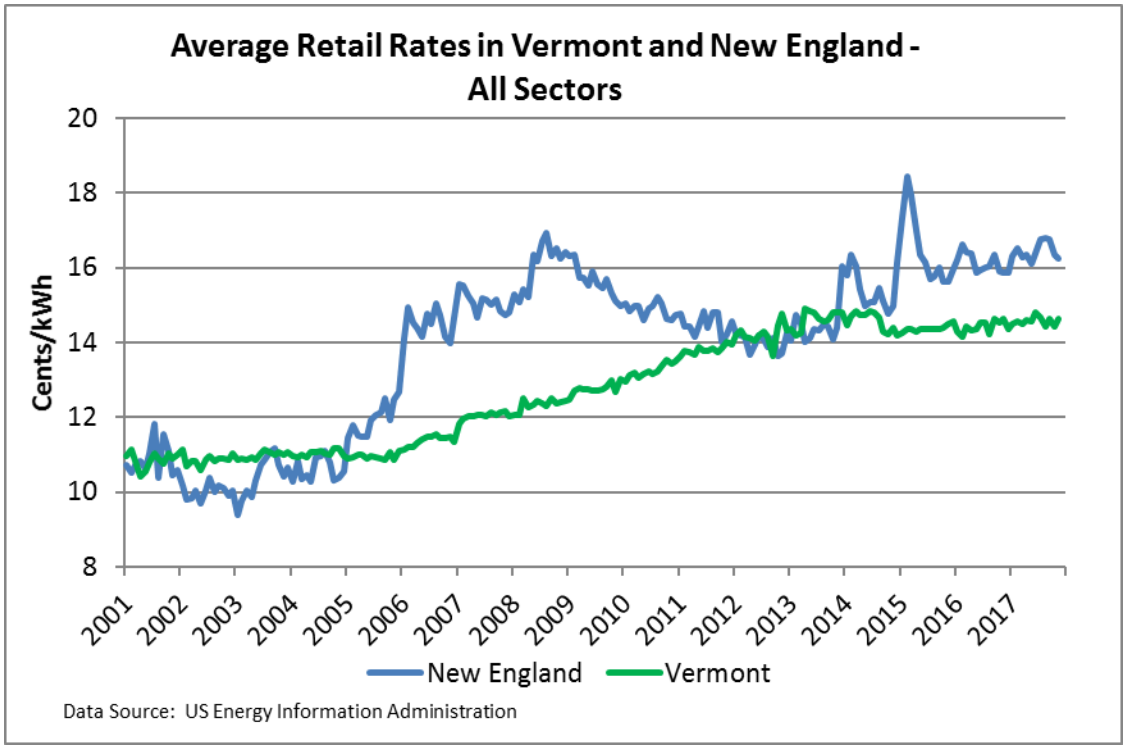
time") market addresses deviations between day-ahead positions and actual generation and load requirements within the region. Congestion pricing components help identify constrained areas with inadequate access to wholesale electricity, sending market signals for infrastructure investment through higher wholesale electric prices (alternatively in areas with excess generation, congestion pricing can reduce wholesale market pricing signaling that additional generation in the location is undesirable). These market changes introduced more volatility to energy prices relative to the more regulated electricity markets of the 20th century. This has increased the need for long-term stably-priced power resources to reduce the effects of market swings on ratepayers though it does require careful consideration in locating such resources in relation to the load being served.

In recent history, in most hours natural gas has been the fuel burned by marginal-unit generators in the New England market, resulting in a strong relationship between the prices of natural gas and electrical power. While the United States has experienced a surplus of natural gas supply, the availability of pipeline transportation to New England has become a major constraint. Volatility in recent winter periods can be largely attributed to the restrictions caused by limited-volume natural gas transportation to the New England electricity generation fleet. During the coldest periods, some gas-fired generators have had their generation limited by the lack of fuel available for power production, as natural gas heating customers receive priority deliveries over generators. This has led to increased dispatch of expensive, oil-fired, generation units (or units that normally fire on natural gas but have the ability to switch to oil when natural gas is unavailable) raising the cost of electricity to the region during exceptionally cold periods. A winter reliability program was implemented in winter 2012/13 and ran through winter 2017-18. The program, which was modified from year to year, aimed to address concerns of insufficient fuel on hand in the region when the natural gas system is constrained. The program incentivized generators that could run on oil and liquified natural gas to secure fuel before winter by compensating them. The program resulted in reduced price volatility in the winter but carried a cost of its own. Winter 2017-18 was the last year for the winter program. In June 2018, Pay for Performance ("PFP")

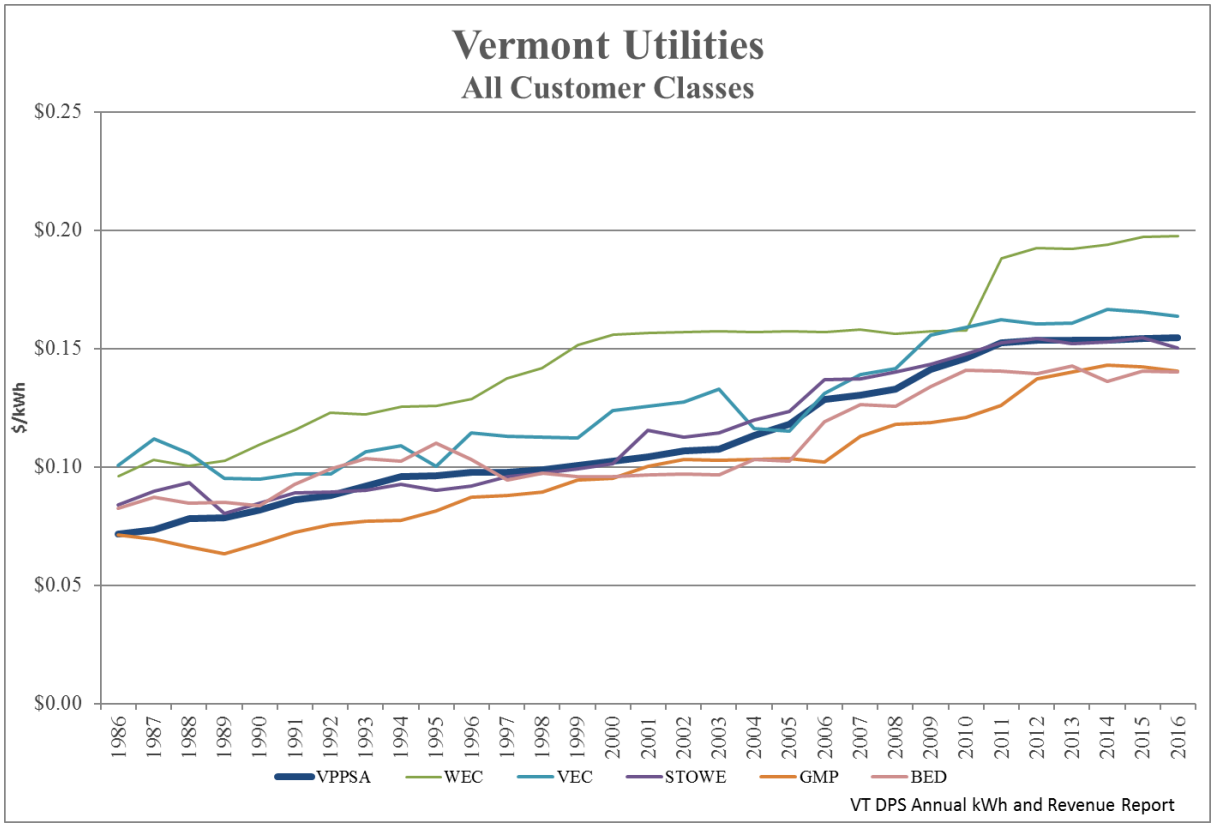
becomes effective, and has stronger FCM incentives to invest in operational improvements and secure fuel arrangements.

## 4) Retail Rates in the State of Vermont

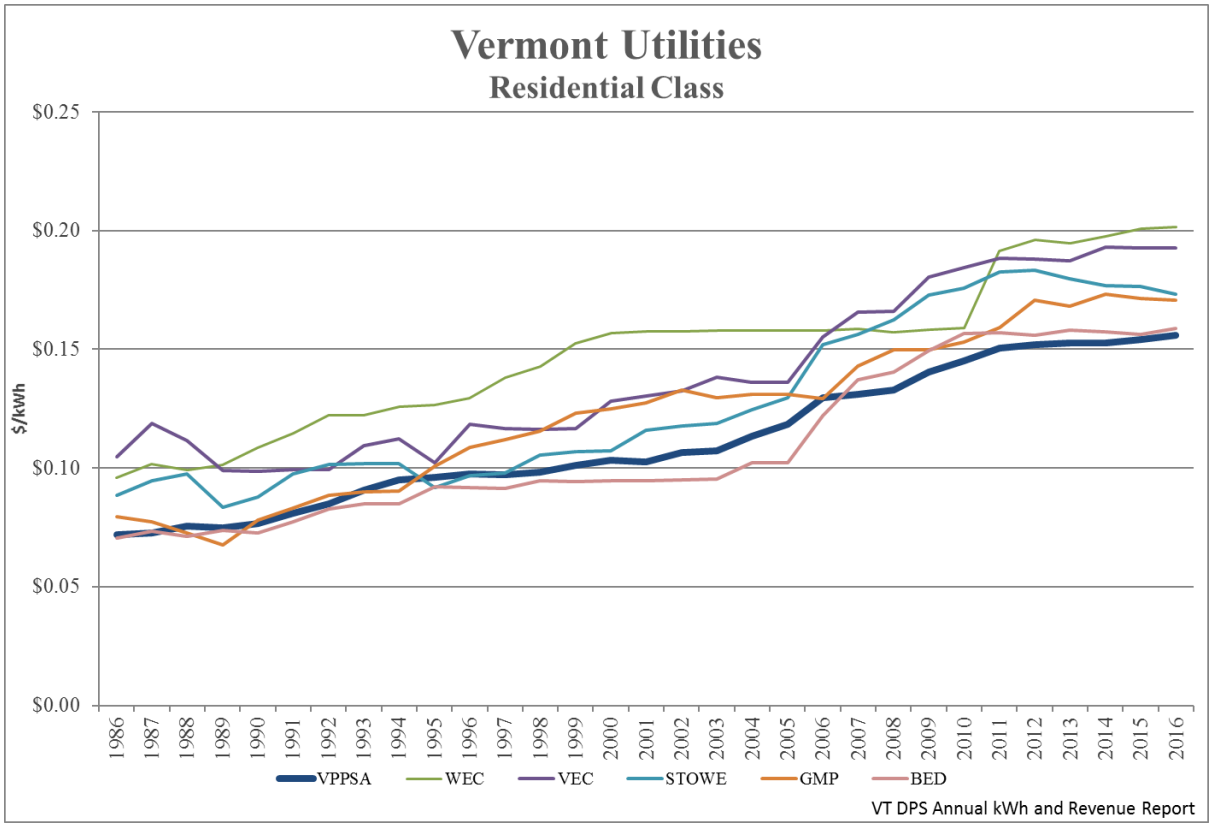
The State of Vermont's average retail rates, as reported by the Department of Energy's Energy Information Administration (EIA), are currently below the New England average and have remained stable. The following chart shows the average retail electric rates for all sectors in Vermont compared to other New England states. Vermont's decision not to restructure its electric industry has helped reduce rate volatility and the need for substantial rate increases due to short-term price movement. Customers in Vermont have received significant portions of their power from long-term stably-priced contracts and utility-owned generation while customers in the rest of New England are comparatively exposed to wholesale market price changes. Wholesale electrical power prices reached historic lows in the 2011-12 timeframe, then reached both highs and lows in 2015, illustrating the volatility of the market. The impact of long-term, price-stable resources is apparent in Vermont rates.



The following chart shows a comparison between the VPPSA member systems and all other Vermont utilities using data from the "kWh and Revenue Report" published annually by the Vermont Public Service Department. It depicts total reported utility revenue from all classes divided by total reported kWh sales for all classes by year ($/kWh). VPPSA member systems, as an aggregate, are in the middle of all utilities in the state.




The next chart shows a similar comparison, specifically for residential rate classes between the VPPSA member systems and all other Vermont utilities using data from the "kWh and Revenue Report" published annually by the Vermont Public Service Department. It depicts utility revenue from the residential class divided by reported residential class kWh sales by year ($/kWh). VPPSA member systems, as an aggregate, are currently the lowest of all utilities in the state. In total, roughly half of VPPSA member systems' kWh sales are from customers in the residential class.




The following tables rank all utilities in the state from highest to lowest Utility Annual Revenue per kWh by rate class for 2016. The VPPSA member systems are listed individually, and in aggregate at the bottom of the table. The data is from the "kWh and Revenue Report" published annually by the Vermont Public Service Department. It is useful to note that many VPPSA systems have mostly residential class customers.

| Vermont Utility All Customer Class Revenues Annual Revenues/kWh Sales | |
|---|---|
| **UTILITY** | **2016 ($/kWh)** |
| WEC | $0.1976 |
| BARTON | $0.1952 |
| HYDE PARK | $0.1812 |
| HARDWICK | $0.1773 |
| JOHNSON | $0.1748 |
| JACKSONVILLE | $0.1714 |
| VEC | $0.1636 |
| LUDLOW | $0.1581 |
| MORRISVILLE | $0.1568 |
| **VPPSA** | **$0.1546** |
| LYNDONVILLE | $0.1538 |
| ENOSBURG FALLS | $0.1504 |
| STOWE | $0.1504 |
| ORLEANS | $0.1427 |
| GMP | $0.1404 |
| BED | $0.1402 |
| NORTHFIELD | $0.1333 |
| SWANTON | $0.1309 |
| | |
| ALL UTILITIES | $0.1440 |
| VPPSA | $0.1546 |

| Vermont Utility Total Residential Class Revenues Annual Revenues/kWh Sales | |
|---|---|
| **UTILITY** | **2016 ($/kWh)** |
| WEC | $0.2014 |
| VEC | $0.1927 |
| BARTON | $0.1918 |
| HARDWICK | $0.1786 |
| HYDE PARK | $0.1782 |
| JOHNSON | $0.1743 |
| STOWE | $0.1733 |
| GMP | $0.1708 |
| JACKSONVILLE | $0.1699 |
| ENOSBURG FALLS | $0.1607 |
| BED | $0.1589 |
| MORRISVILLE | $0.1573 |
| **VPPSA** | **$0.1558** |
| LYNDONVILLE | $0.1554 |
| NORTHFIELD | $0.1380 |
| LUDLOW | $0.1351 |
| ORLEANS | $0.1298 |
| SWANTON | $0.1288 |
| | |
| ALL UTILITIES | $0.1723 |
| VPPSA | $0.1558 |

| Vermont Utility Total Commercial and Industrial Class Annual Revenues/kWh Sales | |
|---|---|
| **UTILITY** | **2016 ($/kWh)** |
| BARTON | $0.2072 |
| HYDE PARK | $0.1901 |
| JOHNSON | $0.1752 |
| JACKSONVILLE | $0.1751 |
| HARDWICK | $0.1741 |
| WEC | $0.1710 |
| LUDLOW | $0.1699 |
| MORRISVILLE | $0.1564 |
| **VPPSA** | **$0.1535** |
| LYNDONVILLE | $0.1522 |
| ORLEANS | $0.1486 |
| STOWE | $0.1410 |
| ENOSBURG FALLS | $0.1390 |
| BURLINGTON | $0.1342 |
| VEC | $0.1339 |
| SWANTON | $0.1330 |
| NORTHFIELD | $0.1305 |
| GMP | $0.1238 |
| | |
| ALL UTILITIES | $0.1271 |
| VPPSA | $0.1535 |

VT DPS Annual kWh and Revenue Report

Utilities in Vermont have dramatically different customer class percentages within their systems resulting in significant variations in load shape. This variation in class is largely responsible for the discrepancies that can be seen in the prior tables. The table below lists the class percentage of total sales by system with the VPPSA member systems listed individually, and in aggregate at the bottom of the table. The data is from the "kWh and Revenue Report" published annually by the Vermont Public Service Department.

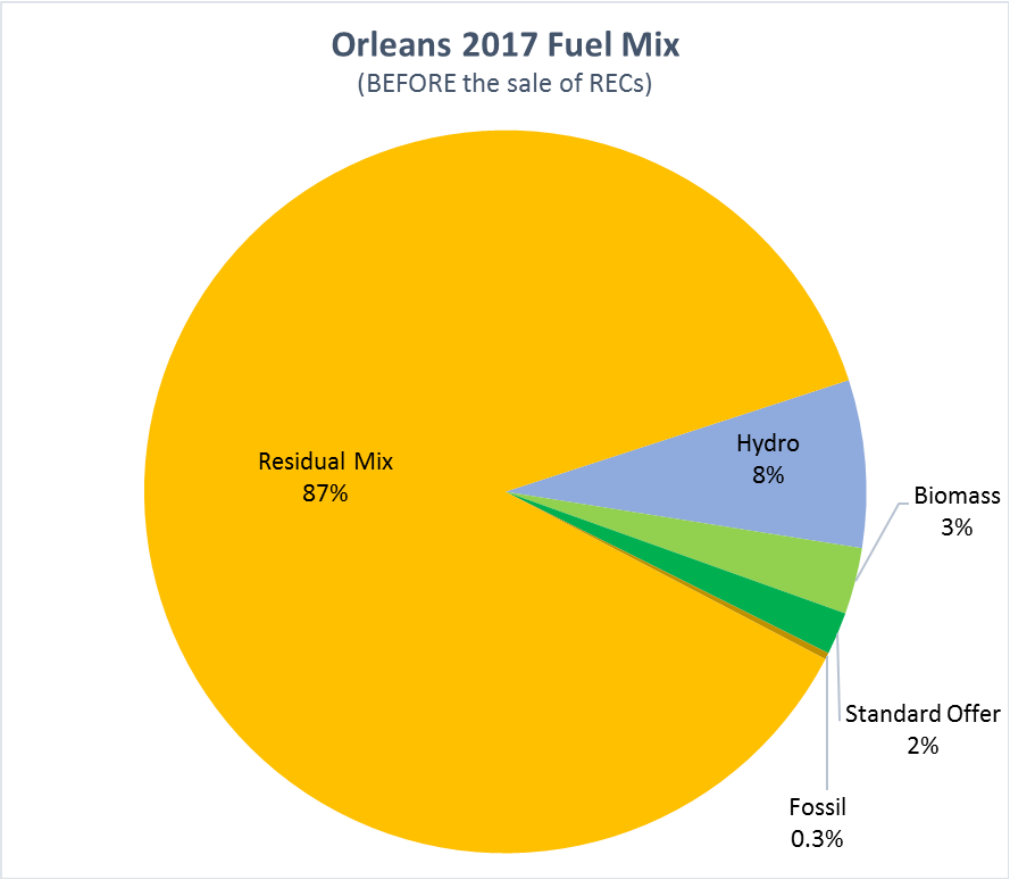
| Vermont Utility Total Residential Class Residential Class kWh Sales /Total | |
|---|---|
| UTILITY | 2016 (%) |
| WEC | 87% |
| BARTON | 78% |
| HYDE PARK | 74% |
| JACKSONVILLE | 71% |
| HARDWICK | 71% |
| LYNDONVILLE | 51% |
| ENOSBURG FALLS | 53% |
| VEC | 50% |
| VPPSA | 50% |
| SWANTON | 49% |
| MORRISVILLE | 47% |
| JOHNSON | 42% |
| LUDLOW | 34% |
| GMP | 35% |
| NORTHFIELD | 38% |
| ORLEANS | 31% |
| STOWE | 29% |
| BURLINGTON | 24% |
| | |
| ALL UTILITIES | 37% |
| VPPSA | 50% |

| Vermont Utility Total Commercial and Industrial Class C&I Class kWh Sales /Total | |
|---|---|
| UTILITY | 2016 (%) |
| WEC | 13% |
| BARTON | 22% |
| HYDE PARK | 26% |
| JACKSONVILLE | 29% |
| HARDWICK | 29% |
| ENOSBURG FALLS | 47% |
| LYNDONVILLE | 49% |
| VEC | 50% |
| VPPSA | 50% |
| SWANTON | 51% |
| MORRISVILLE | 53% |
| JOHNSON | 58% |
| NORTHFIELD | 62% |
| GMP | 65% |
| LUDLOW | 66% |
| ORLEANS | 69% |
| STOWE | 71% |
| BURLINGTON | 76% |
| | |
| ALL UTILITIES | 63% |
| VPPSA | 50% |

VT DPS Annual kWh and Revenue Report

# 5) Existing Resources

Orleans's power supply portfolio is made up of owned generation resources, long-term contracts, and short-term contracts. The diversified portfolio is a hedge for the cost of serving load at the Vermont Zone in the ISO-NE market system. Orleans's 2017 fuel mix is summarized in the following chart. Additional information is provided in the table that follows. A brief description of each resource concludes this section.




| Resource | 2017 Max Qualified Capacity | 2017 kWh | Type | Description | Fuel | Location | Expiration |
|---|---|---|---|---|---|---|---|
| NYPA | 95 | 713,280 | ATC | Block Power | Hydro | Roseton Interface | Varies |
| VEPPI-Hydro | 37 | 340,395 | Varies | PURPA Units | Hydro | Various VT nodes | Varies |
| Ryegate | 50 | 418,797 | Baseload | PURPA contract | Wood | UN.BARRE_VT34.5RYGT | 10/31/2021 |
| P10 | 3,393 | 41,806 | Peaker | Dispatched | Fuel Oil | UN.HIGHGATE13.8SWC1 | Life of Unit |
| Standard Offer | 3 | 268,575 | Varies | In-State Renewable | Various Renewable | Varies | Varies |
| Market Contracts | N/A | 12,030,901 | Daily | ISO-NE bilateral | System Mix | Mass Hub | Varies from 2009-2017 |

*New York Power Authority (NYPA)*

The New York Power Authority provides hydroelectric power to the utilities in Vermont under two contracts. The first contract is a 1 MW 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 14.3 MW entitlement to the Niagara Project located at Niagara Falls, New York. The contract for St. Lawrence has been extended through April 30, 2032. The Niagara Contract has been extended through September 1, 2025.

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

Orleans receives power from several independent power producers (IPP) as mandated by Rule 4.100 appointed purchasing agent. Vermont Electric Power Producers, Inc. (VEPP Inc.) assigns power to all Vermont utilities under Vermont Public Utility Commission (PSB) Rule 4.100 based on a pro-rata share of electric sales, updated annually. Contracts between VEPP Inc. and its constituent power producers began to terminate in 2008, with the last contract scheduled to end in 2020 (i.e. by the end of the period covered by this report).

*Ryegate Biomass*

Barton receives power from Ryegate biomass facility through a state mandated arrangement administered by the State appointed purchasing agent. Vermont Electric Power Producers, Inc. (VEPP Inc.) assigns power to all Vermont utilities based on a pro-rata share of electric sales which is updated annually. The contract expires 10/31/2021.

*Project 10*

Orleans held a municipal vote to authorize the execution of a Power Sales Agreement (PSA) with Vermont Public Power Supply Authority for 7.10% of a 40 MW peaking facility constructed in Swanton, Vermont. Eleven municipal utilities and one Vermont cooperative have signed Purchase Sales Agreements for the project which came online in 2010. Project 10 has benefited significantly from stronger New England capacity prices beginning in June 2017.

The project constructed 46 MW of fast-start generation capacity designed to provide reliability services to the participating municipal utilities at prices below projected New England market prices over the life of the facility. Additionally, the

facility runs during peak price times to mitigate price spikes that occur when New England loads reach peak levels in the summer and winter.

*Standard Offer*

Orleans receives power from dozens of independent power producers according to the state mandate set forth in the Vermont Energy Act of 2009 (i.e. Act 45) which is administered by the Sustainably Priced Energy Enterprise Development (SPEED) facilitator. The prices paid to developers under Act 45 were initially standardized based on the type of renewable energy technology; however, in April 2013 the SPEED facilitator implemented a price-based Request for Proposals for developers of Standard Offers projects. Orleans receives a share of all Standard Offer contracts based on its pro rata share of Vermont's prior-year kWh retail sales. The duration of standard offer contracts is permitted to be between 10 and 20 years except for solar which may be contract for up to 25 years.

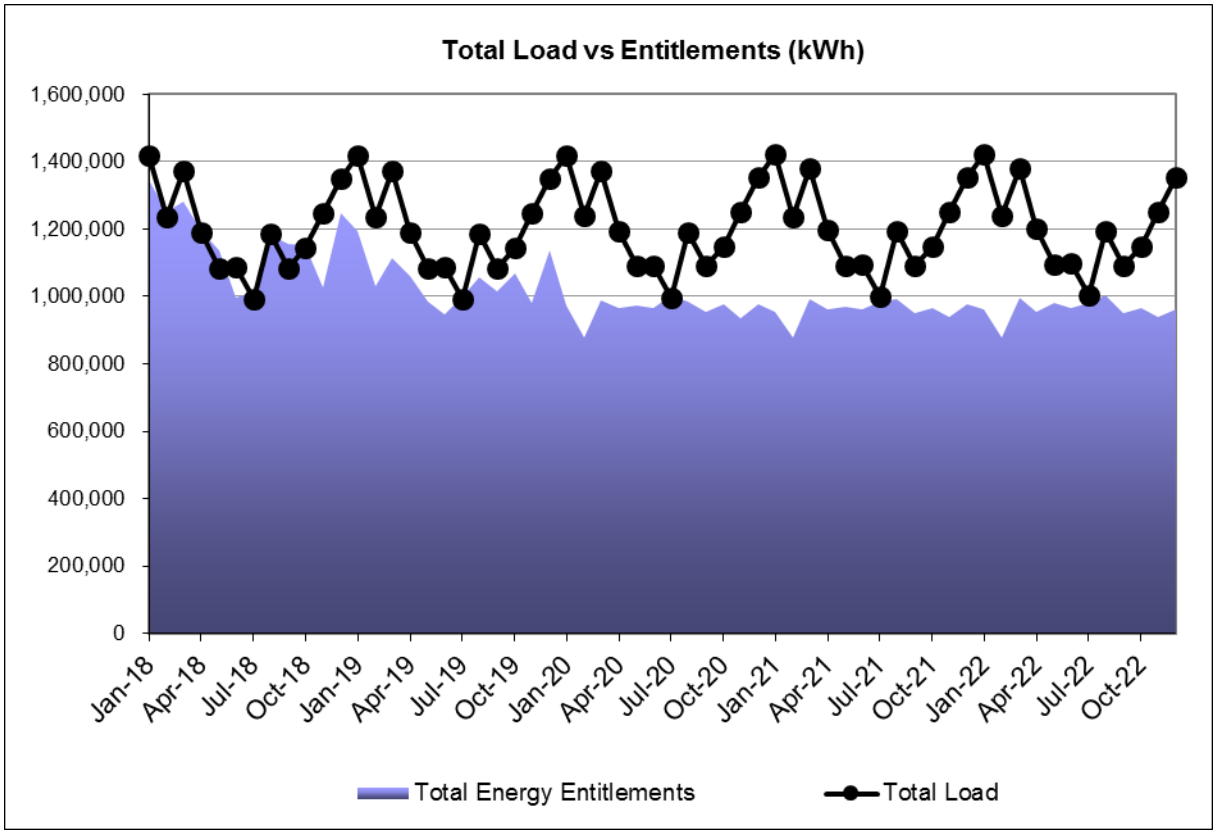
*Market Purchases*

Orleans meets the remainder of its load obligations through ISO-NE's day-ahead and real-time energy markets, physical bilateral transactions, and financial transactions. Orleans participates in the wholesale markets based on its forecasted energy requirements. Short-term transactions are made periodically to adjust the portfolio in an effort to match resources to Orleans's load obligations. Market purchases range in size, duration, and counterparty. Market purchases longer than five years in duration or above certain quantities of historic peak load require Vermont Public Utility Commission approval.

# 6) Market Position

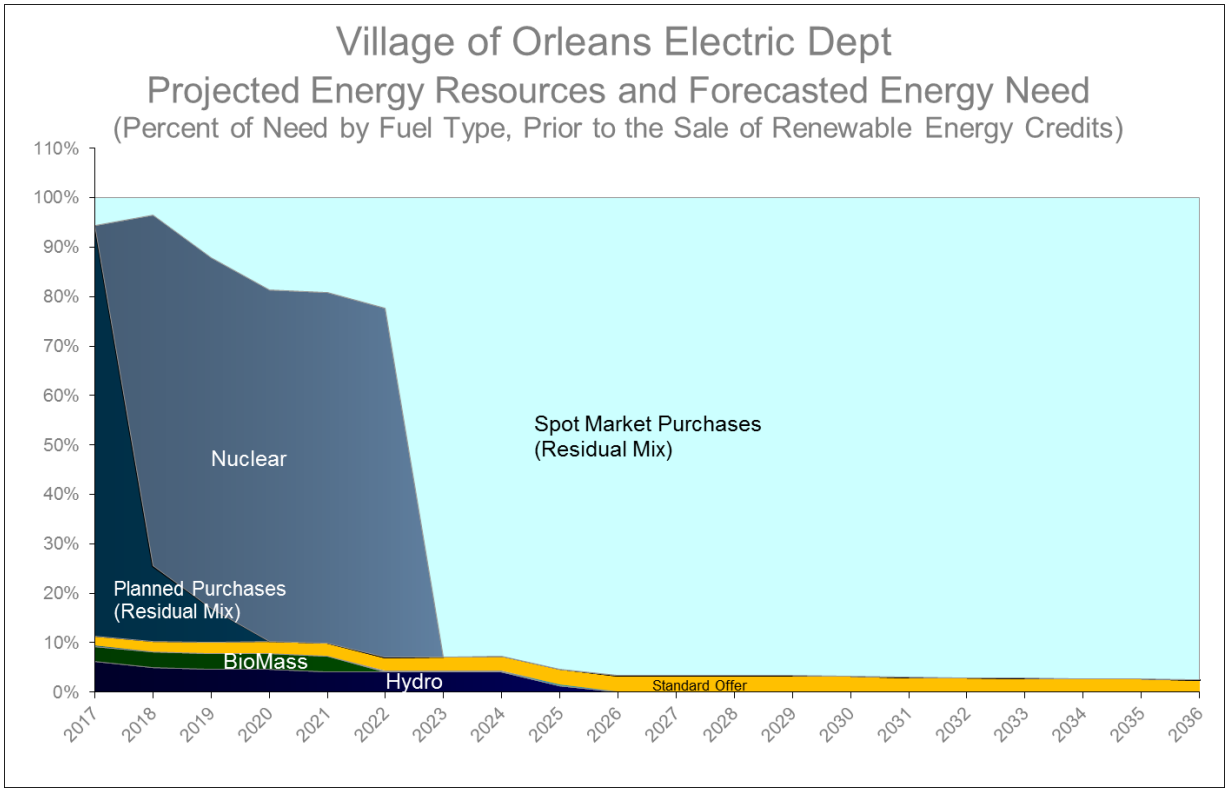
*Energy*

Energy is the largest component of a utility's power costs. Presented below is a chart of Orleans's projected energy resources available from existing contracts and generating plants relative to the monthly forecast of load from 2018 through 2022.




Note the relationship between forecasted energy needs and Orleans's power supply resources. Gaps represent an under (or over) commitment of power resources as compared to projected load on a monthly basis. As supply falls below load Orleans will acquire new resources that meet the utility's decision making-criteria.

VPPSA continually evaluates power markets on Orleans's behalf for economical solutions to address future energy needs. VPPSA and Orleans seek to diversify the portfolio fuel mixture and to employ renewable solutions whenever possible. The graph below shows Orleans's generation outlook by fuel type over the next 20 years.

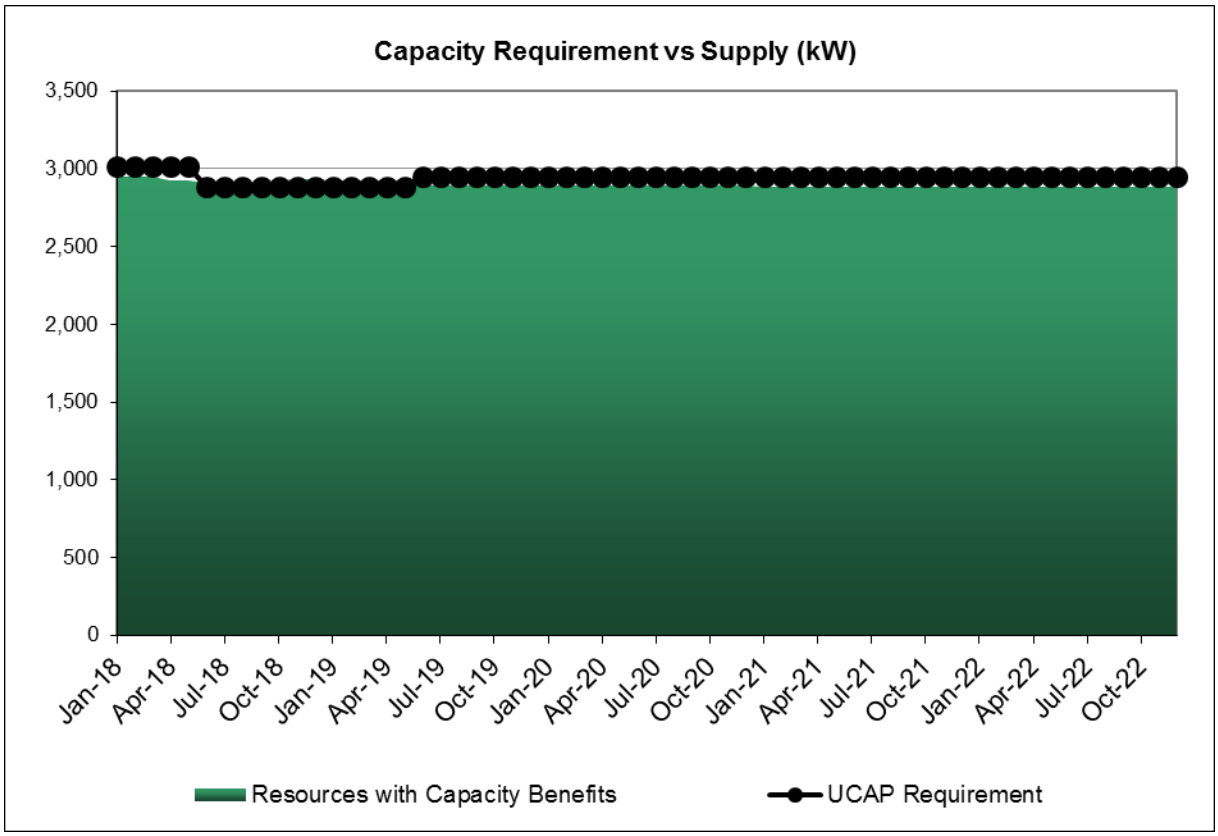



# 7) Capacity Position

*Capacity*

Capacity is another major cost driver in a utility's power costs. Capacity represents the capability to generate electricity and is required for utilities that purchase wholesale electricity in the New England market.

The graph below shows Orleans's capacity available from existing resources compared to its projected capacity requirements as a participant in ISO-NE wholesale markets. "Capacity Load Obligation" represents the forecasted amount of capacity Orleans will be obligated to procure.




*Forward Capacity Market*

The Forward Capacity Market (FCM), which became active in 2010, is a market designed to ensure the region has sufficient capacity to meet its peak demand. Orleans's market capacity resources are credited the auction clearing price for the commitment period. Conversely, as a load serving entity, Orleans will be charged based on its peak contribution (load at the time of New England's annual peak). The peak contribution is then grossed up by a "reserve margin" to determine the Capacity Requirement. Any load reducing resources that are not participating in the ISO-NE market have the effect of reducing the utility's Capacity Requirement.

Forward Capacity Auctions (FCA) are held annually to procure capacity three years in advance of the need for capacity. Procurement amounts are based on the forecasted need for capacity during the period for which the auction is held. Capacity resources to which Orleans is entitled via ownership or contract have generally been offered and accepted in each capacity auction, resulting in a Capacity Supply Obligation (CSO) for each auction commitment period. Orleans has used this cleared capacity to

help offset its CLO and Capacity Requirement.

The first Forward Capacity Auction took place in February 2008, for capacity year 2010-2011. The results from this auction set a new price for capacity for the period June 2010 to May 2011 (capacity cleared at the administratively set floor price of $4.50 kW-mo in the first auction). Subsequent auctions have been held for capacity periods through 2018. The table below summarizes clearing prices obtained in the auction process.

| Auction | Clearing Price |
|---|---|
| FCA #1 (2010-11) | $4.50/kW-mo. |
| FCA #2 (2011-12) | $3.60/kW-mo. |
| FCA #3 (2012-13) | $2.95/kW-mo. |
| FCA #4 (2013-14) | $2.95/kW-mo. |
| FCA #5 (2014-15) | $2.21/kW-mo. |
| FCA #6 (2015-16) | $3.43/kW-mo. |
| FCA #7 (2016-17) | $3.15/kW-mo. |
| FCA #8 (2017-18) | $7.03/kW-mo. |
| FCA #9 (2018-19) | $9.55/kW-mo. |
| FCA #10 (2019-20) | $7.03/kW-mo. |
| FCA #11 (2020-21) | $5.30/kW-mo. |
| FCA #12 (2021-22) | $4.63/kW-mo. |

The capacity market rules have continually changed since its inception. The implementation of administratively set prices, methods for setting the amount of solicited capacity, and participation for renewable resources, are just three examples of the types of fundamental pieces of the market that have changed since the start of the FCM. Effective June 2018, PFP will be in place to incentivize capacity resource owners to make investments to ensure their resources reliability during periods of scarcity. Additionally, ISO-NE has recently proposed further changes to address methods by which state-sponsored policy resources can participate in the markets. On Orleans's behalf VPPSA monitors and participates in market design and evaluates the utility's capacity position on an ongoing basis.

## 8) Future Long-Term Resources

VPPSA assists Orleans in evaluating resources to replace any existing long-term resources or fill any long-term need. At this time VPPSA has negotiated for the purchase of output from power projects that are in the planning and development stages as well as other long term contractual opportunities. Details on successfully contracted resources with future start dates are included below.

*2018-2022 Market Purchase*

Orleans participated in a recent transaction to purchase power in the years 2018-2022. The contract provides energy at fixed pricing for the five-year term. This purchase will help Orleans maintain stable, predictable power supply costs through 2022.

*Solar Generation*

VPPSA is investigating several avenues to offer VPPSA members an opportunity to purchase power produced by solar units located in Vermont. In 2017, VPPSA issued a request for proposals soliciting proposals from solar developers for facilities ranging from 1-5MW within VPPSA Member territories. In-state solar generation is expected to help VPPSA's members cover daily load profiles, promote the development of renewable generation at the community level, and meet Renewable Energy Standard (RES) requirements.

## 9) Anticipated Resource Transactions

*Planned Purchasing*

In order to make its members' power costs more predictable, VPPSA implements a plan to purchase power using a systematic technique, helping to avoid uncertainty and volatile price swings. Orleans currently participates in the Planned Purchasing structure through its membership in VPPSA. Under the Planned Purchasing approach VPPSA

reviews Orleans's market exposure at six-month intervals, for two-year forward periods (defined as its forecasted need for power, less amounts available through previously secured long-term contracts and generation).

Periodically, Orleans has the opportunity to purchase a portion of its energy needs for future periods. By staggering purchases Orleans's energy needs are met at any given point by contracts purchased at several different times, resulting in less volatile purchased power prices. As a result of this laddering effect, the utility is expected to avoid large breaks in coverage in the immediate future.

The implementation of Planned Purchasing is structured and systematic, but it does not remove the need for continual market monitoring and judgment. The goal is to use market monitoring and judgment to give the municipal systems the benefit of more favorable resource prices. In the event that market prices are below that which would cause rate pressure, longer duration purchases may be made. In the event that unusually high prices prevail at the time of a planned purchase, the purchase may be delayed.