# 2021
# BIENNIAL REPORT ON RATES

Your Energy Partner®

Omaha Public Power District

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## A) Executive Summary

This is the first Biennial Report on Rates prepared by Omaha Public Power District (OPPD). In the interest of transparency, this report will outline, in detail, proposed changes to OPPD rates across all customer classes. Upon approval from the OPPD Board of Directors, the rate changes outlined here will be effective Jan. 1, 2022.

The continuing transformation of the energy industry necessitates a higher level of visibility and understanding for OPPD customers around rates and the costs it takes to provide them with energy services. These changes also present challenges and opportunities as the utility evaluates how to continue to serve customers amid rising material costs, evolving customer needs, new technology, and other price changes. With these factors, existing price structures no longer accurately reflect the cost to serve customers. The rates detailed here will more accurately reflect the results of the most recent Cost of Service (COS) study.

Guided by OPPD's Strategic Directive around rates (SD-2), the utility looked at ways to adjust its rates to better reflect cost of service and minimize unfair cost shifts among customer classes. OPPD has begun the process of developing rates that will enable customers to collaborate with their public power utility in order to lower their bills and reduce OPPD's costs during peak usage hours.

As a public power utility, OPPD must operate in a revenue-neutral state, meaning all revenue generated by retail sales is directly invested back into the operations of the utility. As a publicly-owned utility, we pride ourselves in keeping our customer-owner's best interest in mind when recovering revenues. The District has begun to take immense measures to adapt our company to meet our customers' needs and offer competitive rates.

OPPD staff recommends an average rate increase of 2.5% across all five customer classes – residential, small general service (commercial), large general service (industrial), lighting and municipal service (wholesale). This increase is driven by several external factors, including the increasing cost of infrastructure, as well as investment in new technology resources for customers and initiatives that will transform OPPD as it moves into the future.

These changes in 2022 will take a step toward better aligning rates with the cost of service for each customer class while providing more accurate price signals for future investments in OPPD's current and future operations.

These are just a few of the many ways the additional revenue from these rate adjustments will be used:

- Capital improvements to our electrical system to serve our growing communities as well as maintain the health of our existing structures and equipment.
- Implement technology that will provide customers with the ability to interact with OPPD in new and efficient ways, including new products and services to help them manage their electricity bill.
- Increase the reliability of the system through increased investment in the maintenance of overhead lines.

These budgetary increases will directly benefit customers, how they engage with their utility, and maintain and improve reliability and resiliency of the energy services OPPD provides.

## B) Rate Setting Principles

The District's Strategic Directive 2 (SD-2) states the principles that OPPD shall adhere to when setting rates:

- Maintain fair, reasonable, and non-discriminatory rates as stated in Nebraska Revised Statute 70-655;
- Equitably assign costs across and within all customer classes;
- Monitor affordability indicators;
- Pursue rate process and structure changes to reflect the cost of energy when it is used;
- Offer flexibility and options; and
- Be simple and easy to understand.

The Rate Fundamentals section of this document explains the steps taken to develop rates using the COS to equitably assign costs, and to maintain fair, reasonable and non-discriminatory rates. The District offers a variety of options displayed in OPPD's Service Regulations and Schedules document. In 2020, the Service Regulations and Schedules document was updated to increase the ease of understanding, and we continue to keep that goal in mind when new information is conveyed to customers. The following sections will communicate some additional steps taken to adhere to these rate-setting principles.

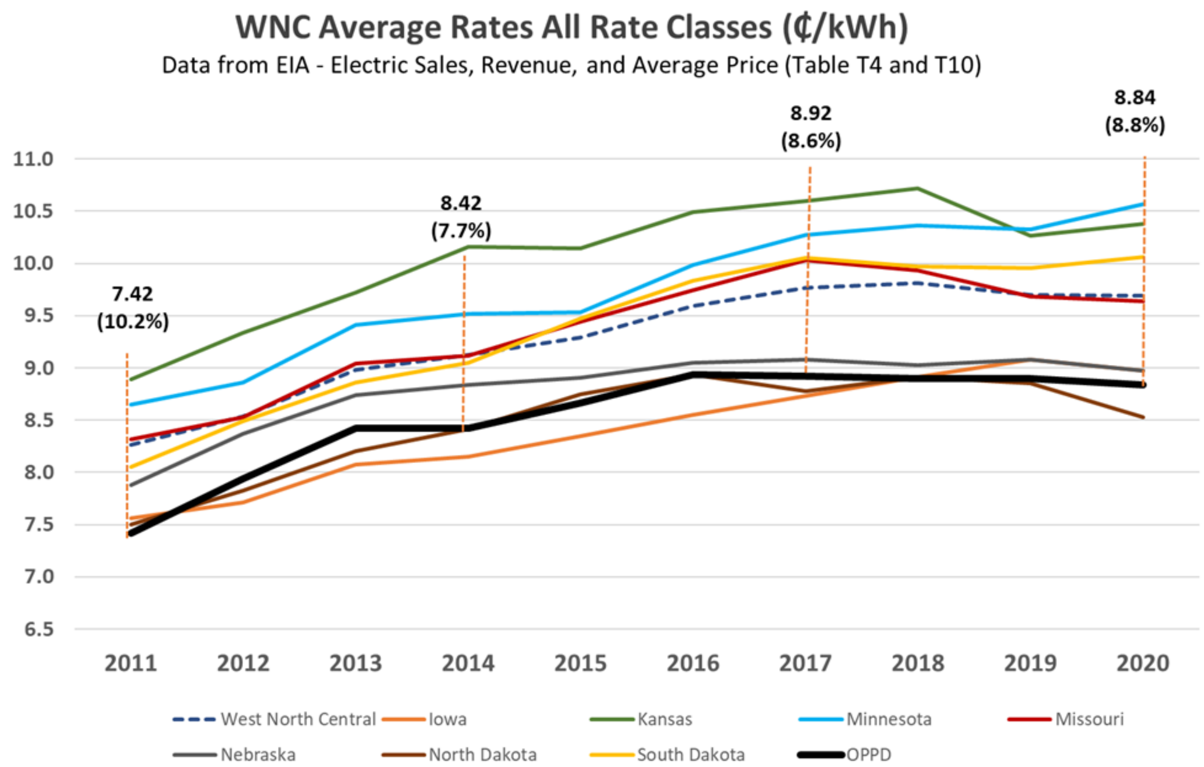
### a) Competitive Retail Rate Comparison

Adhering to our guiding principles, the District compares its rates to other rates in the region to ensure we maintain competitive prices. OPPD practices caution when comparing our retail rate offerings with those utilities around us since there are many factors that will determine if this comparison is a reasonable one to make. The retail price of electricity of a particular utility should not be considered in an isolated manner. There are other factors that need to be considered, such as the utility's customer service level, credit rating, service area extension, concentration of customers and distribution among customer classes, benefits and obligations the utility has in a particular state, and its financial stability, among others. As part of SD-2, the board set a directional rate performance guideline by using the West North Central (WNC) regional average as a benchmark.

The U.S. Energy Information Administration (EIA) is the statistical agency of the Department of Energy that provides policy-independent data and analyses. OPPD uses EIA's published data to compare our rates to the region. EIA's calculation of average price per kWh is as follows:

$$\text{Average Price} = \frac{\text{Retail Revenues (\$)}}{\text{Retail Sales (kWh)}}$$

This methodology ensures comparability regardless of the utility's rate structure. The District compares its rates against the WNC region, which is comprised of North Dakota, South Dakota, Minnesota, Iowa, Missouri, Kansas and Nebraska. The figure below shows the average price per kWh for all rate classes of OPPD compared with states in the region.




OPPD committed to no general rate increase for 5 years starting on January 1, 2017. Since then, in the first 3 years, OPPD moved from 6.8% below the WNC average to 8.8% below the regional average by the end of 2020. Altogether, OPPD's sustained operational savings have helped position ourselves as a utility that offers competitive prices for large general service, small general service and residential growth, which will support new projects and community programs.

### b) Affordability Indicators

As part of SD-2, OPPD monitors affordability using the concept of electricity burden, defined as the percentage of household income that goes towards the electric bill. Utilizing the U.S. Census Bureau's American Community Survey (ACS), OPPD derived its average territory's residential electricity burden as 1.86%. This is estimated to be 13% lower than the Nebraska electricity burden, which is 2.11%.

However, average residential bills do not highlight instances where electricity burden is above levels that OPPD finds undesirable. A higher electricity burden will occur in lower income households and/or in energy-inefficient homes. OPPD, recognizing particular areas of concentration of high electric burdens, is developing programs to expand targeted outreach and communications regarding OPPD's assistance programs.

As a result, while OPPD is sun setting the Low-Income, Low-Use (LULI) assistance program, a new Customer Assistance Program (CAP) Pilot is being implemented in 2022. OPPD's CAP Pilot will have a positive impact on the affordability gap, which is the difference between actual electricity burden and an acceptable burden level. All low-income customers can apply to the new program, regardless of their energy usage, which was not the case with LULI. In addition to this program, the Energy Burden Solutions Initiative recognizes the need to address affordability in a more complex manner and is consequently broadening the scope of our current and future affordability programs.

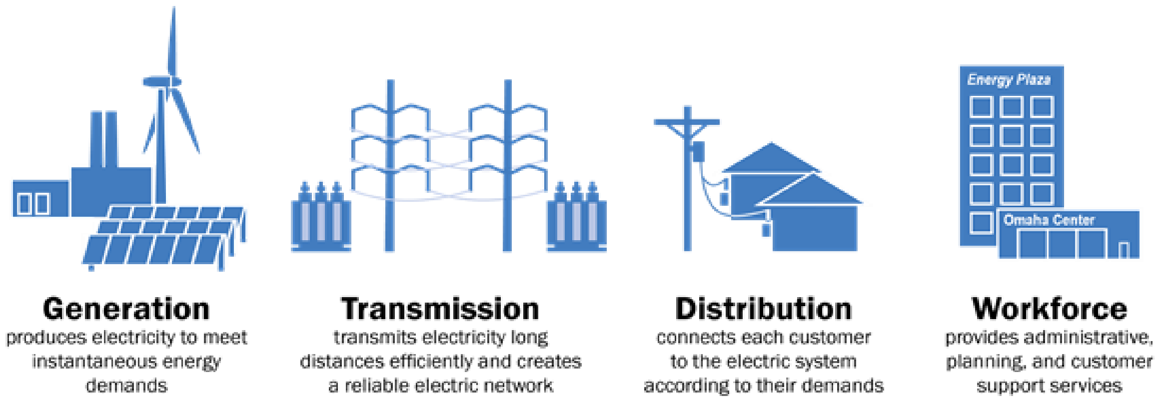
## C) Rate Fundamentals

This section discusses the theoretical and practical application of rate fundamentals set through our COS study. While the electric industry continues to evolve, the fundamentals that determine rate setting are largely based on the same principles that they were decades ago – namely, that the revenue requirement's recovery be collected from the various classes of service based on the relative proportion of their contribution to the costs. This is determined through a COS study. The objectives of the COS study are summarized under the following points:

- Determination of the Revenue Requirement
- Functionalization, Classification and Allocation of Cost
- Rate Design Elements Utilized in Recovery

### a) Determination of the Revenue Requirement

All rate setting starts with the determination of the revenue requirement – how much revenue is needed from our customers. OPPD's revenue requirement is driven by the obligation under SD-3 to maintain certain financial metrics such as adhering to a minimum 2.0 debt-service coverage. Consequently, OPPD's revenue requirement focuses on maintaining debt-service coverage metrics and credit ratings while also covering operating expenses. The revenue requirement is met by both non-retail revenues (off-system sales of energy and other revenues), and retail sales. The 2022 budgeted revenues fall short of the revenue requirement by $26 million. As a result, an increase in the overall average retail rates of 2.5% is required. The section below summarizes the way this 2.5% overall average increase is distributed across our various customer classes.




b) Functionalization, Classification and Allocation of Costs

After the revenue requirement is determined, OPPD conducts a COS study to determine the equitable allocation of the revenue requirement to the various customer classes. The COS study goes through a process of functionalizing, classifying and allocating the revenue requirement to the various classes of service. These terms and the importance of each step of this process are discussed below.

Functionalization refers to the process of dividing the total revenue requirement into three components - generation, transmission and distribution. Typically, functionalization simply follows the assignment according to the standards of financial regulations published by the Federal Energy Regulatory Commission (FERC).

| Functionalization According to FERC | | |
|---|---|---|
| Asset Account Number | Item | Expense Account Numbers |
| 300s - 340s | Production | 500s - 550s |
| 350s | Transmission | 560s - 570s |
| 360s - 370s | Distribution | 580s - 590s |

The process of functionalization is important due to the fact that different rate classes utilize these assets differently. For example, OPPD's distribution assets are used almost entirely by the residential class and small general service customers, made up by the commercial industry. On the other hand, the large general service class, made up by the industrial industry, utilizes very little of the distribution assets since their energy is delivered at higher voltage levels. With such distinction in the asset utilization by different rate classes, functionalization is a critical aspect of properly assigning costs.

After functionalization, costs receive classification. Classification is the process of taking the functionalized costs and classifying these costs based on the driver of the costs. Costs are separated into three principle classifications:

- **Demand** – costs that vary based on the customer's maximum demand, measured in kilowatts (kW).
- **Energy** – costs that vary based on the customer's energy needs, measured in kilowatt-hours (kWh).
- **Customer** – costs that vary with the number of customers on the system.

Classification determines the driver of cost causation.

After costs have been functionalized and classified, the final step in the COS study is the allocation. Allocation is the assignment of the classified costs to customer classes based on the relative proportion of their contribution to those costs drivers. To do a proper allocation of costs, it is essential to understand the characteristics of each customer class, like the number of customers, the energy consumed (kWh), the voltage at which customers take service, and their contribution to the peak demands on the system. These costs, allocated to each rate class, represent the fair apportionment of the revenue requirement. This cost-of-service study is utilized universally in the electric industry as the standard to which customer classes are charged according to their fair share of costs.

### c) Rate Design Elements Utilized in Recovery

Following the allocation of costs, we turn to the recovery of the costs through the rate elements. There are three fundamental rate elements – demand, energy and customer service charges. Ideally, all recovery of costs would match the incurrence with respect to demand, energy and customer costs. Costs that vary based on the maximum demand would be based on a demand charge. Costs that vary based on energy produced would be recovered through an energy charge. Costs incurred, due to the fact that you are a customer that needs to receive service, would be recovered through the customer service charge.

#### i) Demand Charges

Demand charges are derived by taking the demand-related costs and dividing these costs by the "billing demand." This charge is based on the highest amount of power, measured in kilowatts (kW), required by a customer at any particular moment in time. This charge covers the fixed costs such as the production, transmission and distribution demand-related costs. These costs are demand-driven as the sizing of production, transmission and distribution assets is based on customer's maximum demand needs. The recovery of demand-related costs in the absence of a demand charge is discussed in the **Revenue Recovery Application: Two-Part vs Three-Part Rate** section below.

### ii) Energy Charges

Ideally, energy charges should simply reflect recovery of energy costs. This charge varies based on the total amount of energy, measured in kilowatt-hours (kWh), used by a customer over a particular time interval. As an example, this pays for items such as the fuel required to produce electricity and power purchased in the market as the cost driver is the volumetric need for energy.

### iii) Customer Service Charges

Customer service charges are charges used to recover the costs of being a customer, such as billing, collections, and metering. These costs do not change based on demand or energy needs. As OPPD aligns cost recovery according to true cost of service, the customer service charge will not be changed in 2022.

### iv) Revenue Recovery Application: Two-Part vs Three-Part Rate

Not all rates offerings at OPPD provide these three elements due to prohibitive metering costs. Those without demand meters follow a traditional two-part rate structures, charging an energy and customer service charge. The residential and small general service customers, commercial customers, make up those who are on two-part rate structures. For these customers, the energy charge must recover not only energy costs but also generation, transmission, and distribution costs. Increasing diversity of needs in the residential and small general service classes has made it difficult to have all these costs recovered based on a customer's volumetric energy needs.

While in the past these groups represented homogenous classes, they are growing in diversity of needs and are no longer best represented by assuming homogeneity in energy usage profiles. Furthermore, energy efficiencies further complicates the reliance on energy volume to recover fixed costs as overall energy consumption has decreased due to technological advancements. Since fixed costs make up the majority of costs to provide utility services to customers, reliance upon the energy charges to recover fixed costs results in suboptimal recovery.

Transitioning rates towards more sophisticated price signaling and more accurate cost recovery will take a balanced approach over time. These charges need not be based on a flat rate and could incorporate characteristics that align with our cost profile. For example, time-of-use energy rates account for the fact that energy costs not only vary based on the volume of consumption but also based on the time of consumption. Altogether, rate structures utilizing these three elements of demand, energy and customer service charges are the most fair in matching the recovery with the incurrence. More information about how OPPD plans to transition to a more optimal rate structure in the future and the transition towards that goal will be discussed below in Future Focus.

## D) Changes in Revenue Requirement

OPPD is making strategic investment decisions to support the future needs of OPPD's customers. To maintain the ongoing health of our system while also providing these improvements, OPPD recommends an overall average 2.5% increase across customer classes beginning January 1, 2022. The drivers of the increase in the revenue requirement include:

- Strategic transformation investment (Operations & Maintenance Costs)
- Capital funding for infrastructure expansion to serve growing communities
- Sustainability of debt issuance

While OPPD has diligently sought to reduce costs, enabling the 5-year, no general rate increase, many of the cost increases are outside the control of OPPD. Moreover, the overall average 2.5% increase is less than half of the rate of inflation, 5.4%, as defined as by the Consumer Price Index (CPI) over the last 12 months, according to the September 2021 release from the United States Bureau of Labor Statistics.

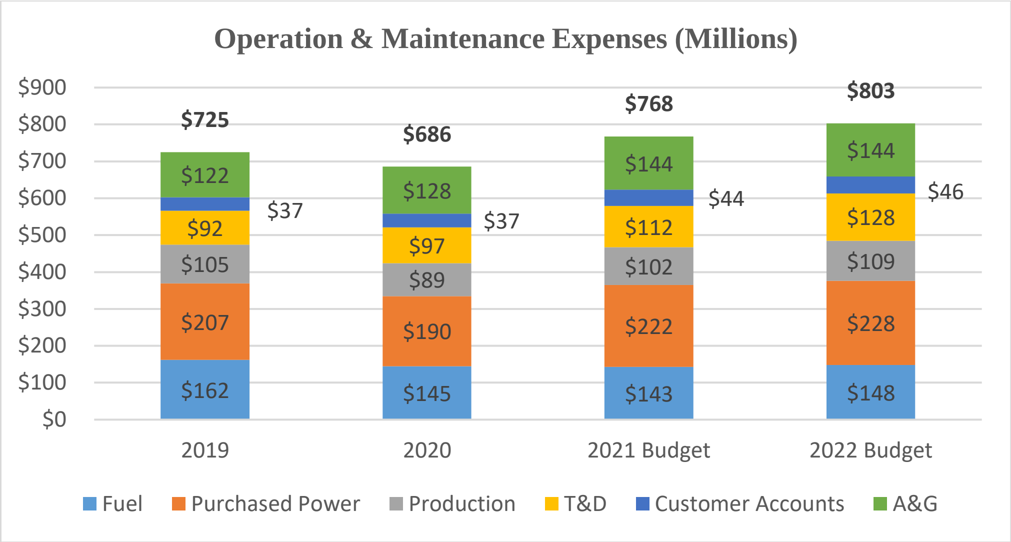
In addition, our prudence in meeting our debt to service ratios, and the board's willingness to act decisively in rate adjustments contribute to our AA bond rating that saves our customers for funds borrowed. Our credit rating allows us to reduce credit expenses, negotiate better purchase power agreements, and contributes to the overall health of OPPD.

The sub sections to follow detail the information regarding the changes anticipated in the revenue requirement categories.

### a) Transformation Investment (Operations & Maintenance Costs):

OPPD is making some strategic investments in many areas to ensure reliability as well as resource the utility for transformation. While there are many details in our $1.8B overall expenditure budget, Operations and Maintenance (O&M) costs provide a good perspective into transformation costs.

The bar chart below provides a trend from 2019 to the 2022 Budget, to provide an illustration of how O&M has grown over time. Specifically, the bar chart shows the $35 million increase in O&M between the 2021 budget and the 2022 budget.




The following narratives highlight our areas of investment for 2022 represented by Operations & Maintenance costs.

### i) Technology, Property, Security and Preparedness:

To position OPPD for a future with increasingly integrated technology, the Technology Platform Strategic Initiative will invest heavily in the modernization of our technology platform. In addition, we are evaluating the District's facilities and whether or not they are appropriate and in good repair for the future workforce.

### ii) Customer Service:

Customer Engagement for the Future Strategic Initiative focuses on new and innovative ways OPPD can engage with customers and their evolving energy needs. As mentioned, the new Customer Assistance Program (CAP) pilot is just one way OPPD addresses affordability on a more complex basis by assisting low-income customers with high energy burdens. This program was highlighted in the **Affordability Indicators** section above.

### iii) Energy Delivery (Transmission and Distribution):

As the utility modernizes, significant and strategic investments are being made in the energy delivery system. Investments in asset health monitoring will help to better manage and reduce asset deterioration. Specifically, low-performing circuits will be addressed to increase reliability. Another example of an investment in existing asset health is the aforementioned maintenance of overhead lines. Nevertheless, expansion to meet our growing customers' needs remains the most critical component of increased energy delivery costs. New distribution and transmission projects require investment costs as well as additional craft and professional positions during the project development.

### iv) Energy Production: Fuel

Since the last rate increase, total fuel and purchased power expense have increased by approximately 30%. Several changes have occurred, including the composition of OPPD's fuel mix.

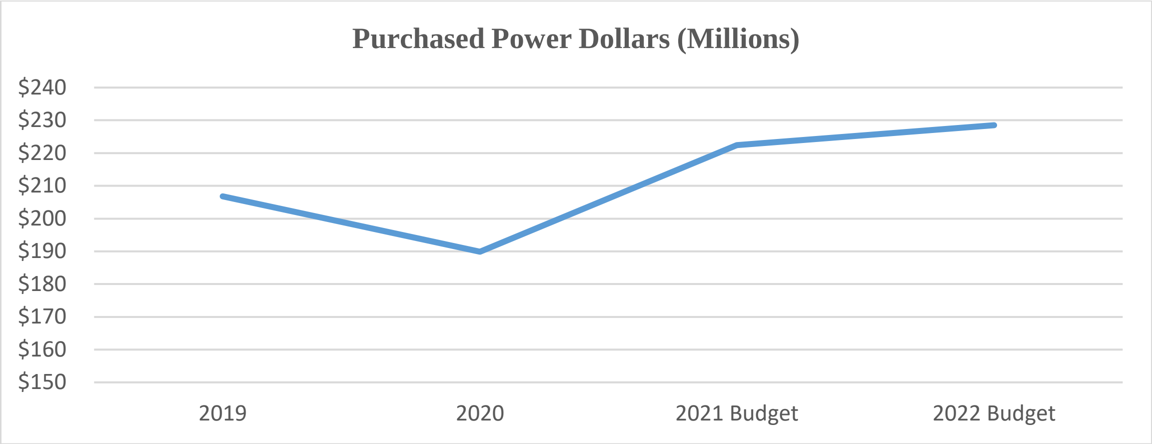
Coal fuel expenses are projected to decrease by 21% in the 2022 budget compared to 2016 due to reductions in total consumption as well as decreases in delivered coal costs. The reduction in total consumption is primarily driven by the refueling of North Omaha Units 1 through 3 from coal to natural gas in 2018. Consequently, natural gas fuel expenses have increased approximately $7 million due OPPD's increase in total natural gas generating capacity. North Omaha Units 1 through 3 are expected to operate at relatively low capacity factors in 2022 due to the higher marginal production cost of natural gas generation. The increase in total natural gas fuel expense in 2022 is driven by both an increase in commodity prices and higher forecasted capacity factors relative to 2016.

It should be noted that a very recent increase in forecasted commodity fuel costs observed in late 2021 is not reflected in the 2022 budget. To avoid having short-term price increase impact our customers, OPPD continues to manage its fuel portfolio and mitigate costs through strategic efforts.

### v) Energy Production: Purchased Power

OPPD load has increased 15% since 2016 due to expansion in our service territory. To support the growth in the eastern Nebraska economy, OPPD expects purchased power costs to continue to increase. Purchased power costs are continually evolving in the Southwest Power Pool (SPP) market. According to the State of the Market 2020 Report, 2020 annual energy prices were down from previous years. However, events like the 2021 polar vortex display how great volatility is possible in purchased power prices. The additions of new generation peaking units will mitigate our risks when peaking events occur and will help reduce our overall purchased power expense during such events in the future. The 2022 budget for purchased power reflects the increased need to meet the growing energy requirements of our customer owners. The graph below demonstrates this marginal growth in purchased power costs over the 2021 budget.

The recent volatility in forecasted commodity prices is not fully reflected in OPPD's 2022 purchased power forecast. OPPD continues to work to mitigate the effects of higher purchased power costs by monitoring its generation assets as well as plan for the maintenance of units during the most opportune times.




### vi) Workforce Impact of Initiatives and Administrative & General Expenses:

Administrative and General Expenses is a significant cost category, which OPPD is focused on managing as part of its operating budget. With investments in technology across multiple business areas, OPPD is aiming to improve the productivity of our workforce. In addition, OPPD is consistently managing non-labor costs such as pension and benefit costs to provide quality employee benefits, while remaining fiscally responsible.

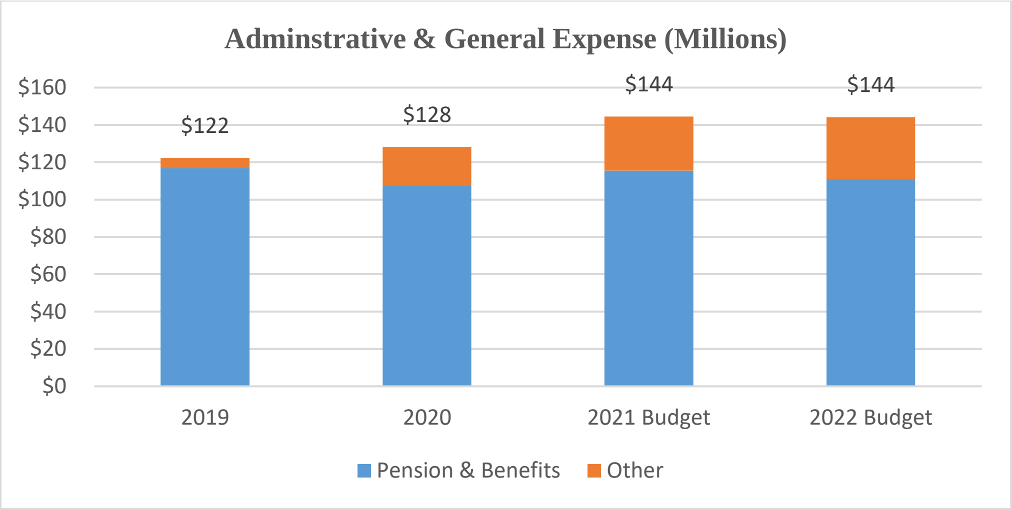
Even though efficiencies in labor productivity is a focus, OPPD has identified a need for headcount growth to support expanding operations especially in technology, customer care, and transmission and distribution. The increase in workforce will enable OPPD to meet our customer expansion and sustainability needs. The table below outlines planned headcount increases in 2022 to support business transformation.

| 2022 Planned Full Time Headcount Growth* | |
|---|---|
| Business Unit | 2022 Budget |
| Technology & Building Facilities | 30 |
| Transmission & Distribution | 27 |
| Customer Service & Public Affairs | 13 |
| Energy Production | 11 |
| All Other | 16 |
| Total | 97 |

**Full time employees excluding Nuclear Decommissioning*

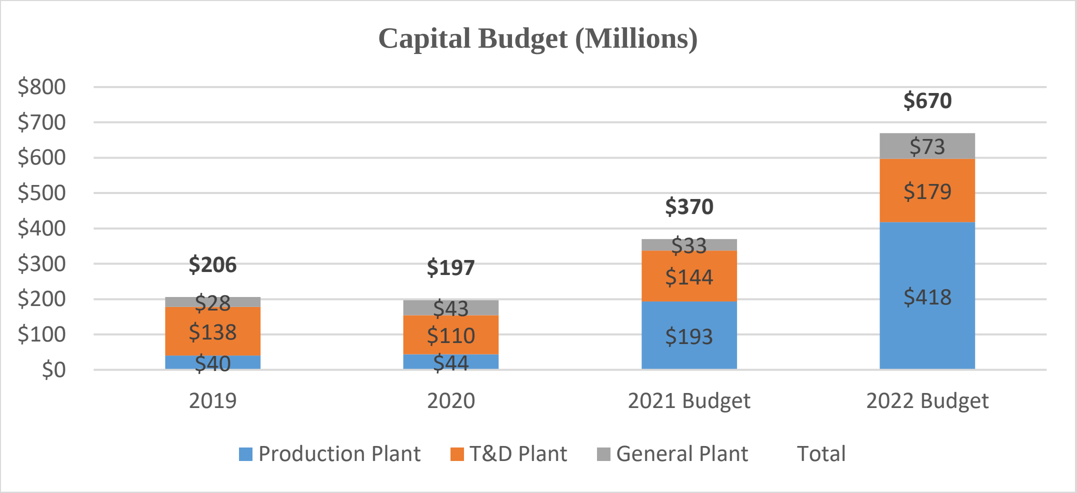
While full-time headcount is expected to grow in 2022, Administrative and General Expenses will remain relatively flat when compared to the 2021 and 2022 budgets.

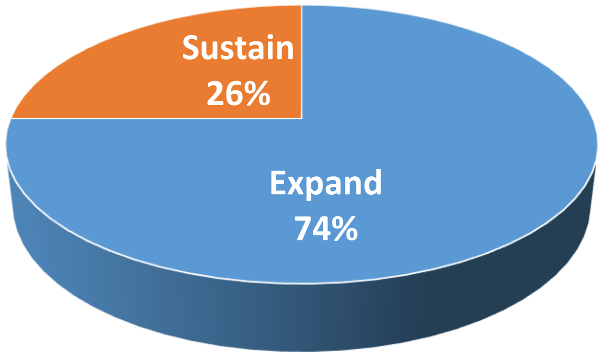
Two major components of the Administrative and General Expense budget are pension and benefit expenses.




## b) Capital Budget and Debt Service

OPPD's capital investment program has grown in the last two years to meet the needs of the communities it serves, while at the same time sustaining the current assets of the District. A major component of the expansion has been the Power with Purpose project, which supports generation, transmission, and distribution for Board Resolution No. 6351 approved on November 14, 2019, to reduce the District's carbon footprint and serve a growing load. Other expansion investments have been made in transmission and distribution to provide reliable electrical service to a growing community. In 2022, a notable increase in technology and facilities investments is reflected in the capital portfolio. The following graphic illustrates the growth in the capital program.






The 2022 Capital Budget total was derived by breaking investments into two categories, labeled sustain and expand. The sustain category includes routine capital projects that are aimed at maintaining and improving existing assets and is budgeted at a consistent level year over year. The expand category is for new assets planned to be added to the District's asset base, such as the Power with Purpose project. The sustain and expand categorization helps to ensure that investment in existing assets is maintained at sufficient levels while new assets are added. For 2022, the sustain category accounts for 26%, or $174.2 million, of the total capital budget and the expand category accounts for 74%, or $495.8 million.

OPPD's revenue requirement is determined by maintaining cash flows and cover existing debt service coverage (DSC) at a 2.0 ratio. OPPD has reduced the amount of debt by not borrowing new funds for six years. However, due to expanding our infrastructure to provide reliable electric service to growing communities, OPPD will issue approximately $358.7 million of Senior Lien Revenue Bonds in late 2021 and plans to issue approximately $394.4 in Senior Lien Revenue Bonds in 2022. These debt issuances contribute to the need for the proposed overall average rate increase of 2.5% to maintain our DSC ratio of 2.0 and minimum of 150 days cash on hand.

The table below compares DSC for the 2021 and 2022 budgets, including the new debt issuance and proposed rate increase.

| Forecast of Debt Service Coverage Information | | |
|---|---|---|
| | 2021 Budget | 2022 Budget |
| Proposed Rate Increase | 0% | 2.5% |
| Deb Issuance ($ M) | $125 | $394 |
| Total Debt Service ($ M) | $124 | $139 |
| Net Available for Debt Service ($ M) | $247 | $278 |
| Debt Service Coverage Ratio | 2.0 | 2.0 |

The combination of our strategic investments both requiring increases in operating expense and the funding through debt issuance to meet our growing energy needs has resulted in the need to increase rates on average 2.5% in 2022.

## E) Retail Revenue Forecast

This section explains the proposed rate increase for 2022. The table below displays the effect of the recommended 2.5% overall average increase by customer class. The difference in percentages among classes represents the overall movement towards removing any revenue shortfall among classes as well as provide adequate cost recovery from the source.

**OPPD 2022 Forecasted Revenues before and after Proposed Rate Increase ($ Millions)**

| Customer Class | 2022 Revenue Forecast | 2022 Proposed Revenue Increase | 2022 Revenue Forecast with Proposed Increase | 2022 Percent Impact |
|---|---|---|---|---|
| Residential | $ 423.8 | $ 13.5 | $ 437.3 | 3.2% |
| Small General Service | $ 320.9 | $ 2.8 | $ 323.7 | 0.9% |
| Large General Service | $ 290.5 | $ 9.3 | $ 299.7 | 3.2% |
| Lighting | $ 17.3 | $ 0.4 | $ 17.7 | 2.5% |
| Wholesale Towns | $ 3.5 | $ 0.0 | $ 3.5 | 0.0% |
| **Total** | **$ 1,056.0** | **$ 26.0** | **$ 1,082.0** | **2.5%** |

*Totals may not add due to rounding

While rate increases compromise our competitive position in the short-term, OPPD recognizes that its goal to maintain prices below regional utilities must be balanced with our commitment to invest in renewable generation, maintain reliability and maintain strong financial metrics for our customer-owners.

## F) Changes in Retail Rates

The changes in the revenue requirement mentioned above require the need to increase retail rates by an overall average of 2.5% in 2022. Based on the results from the COS study, which equitably allocates the revenue requirements of the utility among the various classes of service, each class has a different contribution to the overall 2.5% increase. The class level summary is provided in the section above. The table below provides these increases by rate code. The sections to follow will discuss the cost drivers, rate changes, and bill impacts.

| Proposed Increase by Rate Code | | |
|---|---|---|
| **Class** | **Rate Code** | **Proposed Increase (Decrease)** |
| **Residential** | **Rate 110 – Standard** | 3.2% |
| | **Rate 115 – Conservation** | 3.2% |
| **Small GS** | **Rate 226 – Irrigation** | 0.0% |
| | **Rate 230 – GS Non-Demand** | 0.9% |
| | **Rate 231 – GS Small Demand** | 0.9% |
| **Large GS** | **Rate 232 – GS Large Demand** | 4.9% |
| | **Rate 245 – Large Power – Contract** | 3.7% |
| | **Rate 250 – Large Power** | 5.7% |
| | **Rate 261 – Large Power High Voltage** | 6.6% |
| | **Rate 261M – Large Power HV Market** | (2.4%) |
| **Wholesale** | **Rate 357 – Municipal Service** | 0.0% |
| **Lighting** | **Rate 236 – Dusk-to-Dawn Lighting** | 2.5% |
| | **Rate 350 – Street Lighting** | 2.5% |
| | **Rate 351 – Traffic Signals and Signs** | 2.5% |

### a) All Customer Class Impacts

As discussed in the **Future Focus** section below, OPPD is committing to exploring advanced metering infrastructure to better facilitate both customer experience in our rate offerings and provide proper price signaling to customers. As OPPD transitions to implementing this strategy, customer service charges will be explored based on usage levels and other criteria. With anticipation of a strategic shift in customer service charges, OPPD will not change service charges for any rate code in 2022. This will allow timing for strategic decisions around both the long-term solution with advanced technology and the transitional phase that will prepare customers for the future of rate offerings.

The Fuel and Purchased Power Adjustment (FPPA) factor will remain unchanged at .00186 for 2022. The updates to the FPPA formula are discussed in the **Biennial Rate Package Items** section below.

### b) Residential Rate Changes

The proposed 3.2% increase to the residential class is to further align this class with the COS revenue requirement. Both the standard Rate 110 and Rate 115 would receive on average a 3.2% increase. However, Rate 110 will experience the rate increase during the summer months while Rate 115 will experience the rate increase during the non-summer months. The rationale for this change is discussed in the **Rate Change** section below.

Overall, the revisions in rates have a progressive impact, with customers with high consumption receiving higher impacts.

Currently, several customers remain on the restricted multifamily Rate 119. This rate has been restricted since 2013. We propose eliminating this rate and moving those on Rate 119 to Rate 110 as the costs to serve these customers are the same.

### i) Cost Drivers

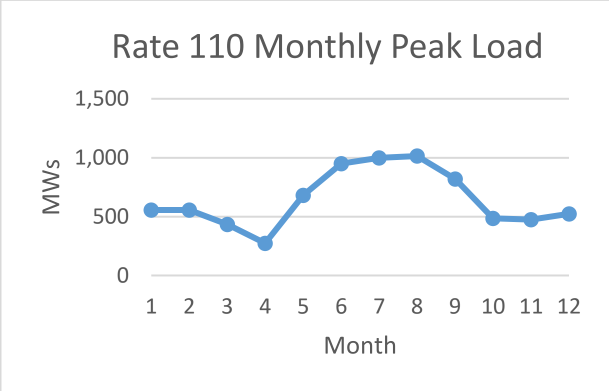
While the overall average need for retail revenues is a 2.5% increase, the residential class has incurred a larger share of the costs driving the need for the rate increase.

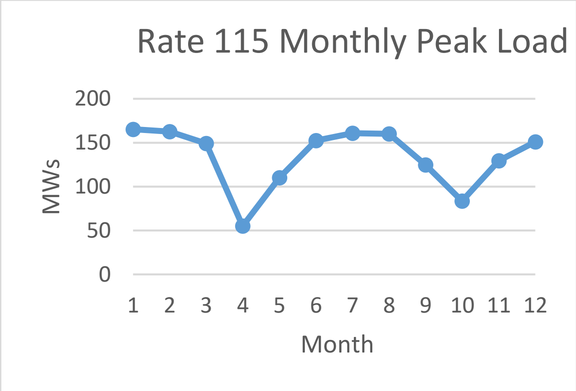
Investments at the customer level and distribution level impact residential customers more than the small general service and large general service because these classes do not utilize these services. With improvements in the maintenance of overhead lines, customer service expenses, and other customer and distribution expenses growing over the last several years and continuing to grow, these cost drivers contribute to the need to raise residential rates.

### ii) Rate Changes

As stated, the customer service charge will not change in 2022. Thus, the increase will occur in the energy charge. While both Rate 110 and Rate 115 are receiving the same average increase of 3.2%, these residential rate offerings will differ in the timing they will experience the rate increase.

Traditionally, these rates have had the same energy charge in the summer and the only distinction occurred in the third tier of the non-summer months. However, these customers have different load profiles, as illustrated in the graphs below. Rate 115 customers use heat pumps and thus more uniformly use energy throughout the year with their peak occurring in January rather than July. Alternatively, Rate 110 customers consist mostly of customers who utilized natural gas to heat and thus peak usage occurs during the summer months.



To better align customer rates with when they are incurring costs to OPPD and utilizing our system, Rate 110 will see the increase occur in the summer months while Rate 115 will see the increase in non-summer months. This structure sends customers in these classes the correct price signal. For Rate 110 customers, it encourages conservation during the summer months. For Rate 115, conservation is encouraged during both the coldest winter and warmest summer months. The new energy charges are detailed in the tables below.

| Rate | Billing Components | Current Rate Summer | Current Rate Non-Summer | Proposed Rate Summer | Proposed Rate Non-Summer |
|---|---|---|---|---|---|
| 110 | Energy Usage<br>0 - 100 kWh<br>101 - 1000 kWh<br>1001+ kWh | <br>9.36 ¢/kWh<br>9.36 ¢/kWh<br>9.36 ¢/kWh | <br>8.63 ¢/kWh<br>7.46 ¢/kWh<br>5.27 ¢/kWh | <br>**10.25 ¢/kWh**<br>**10.25 ¢/kWh**<br>**10.25 ¢/kWh** | <br>8.63 ¢/kWh<br>7.46 ¢/kWh<br>5.27 ¢/kWh |
| 115 | Energy Usage<br>0 - 100 kWh<br>101 - 880 kWh<br>881+ kWh | <br>9.36 ¢/kWh<br>9.36 ¢/kWh<br>9.36 ¢/kWh | <br>8.63 ¢/kWh<br>7.46 ¢/kWh<br>4.31 ¢/kWh | <br>9.36 ¢/kWh<br>9.36 ¢/kWh<br>9.36 ¢/kWh | <br>**9.02 ¢/kWh**<br>**7.85 ¢/kWh**<br>**4.84 ¢/kWh** |
| 119 | Energy Usage<br>0 - 100 kWh<br>101 - 400 kWh<br>401+ kWh | <br>9.36 ¢/kWh<br>9.36 ¢/kWh<br>9.36 ¢/kWh | <br>8.63 ¢/kWh<br>7.46 ¢/kWh<br>3.31 ¢/kWh | Eliminate Rate | |

### iii) Bill Impacts by Usage Levels

The below tables show the bill impacts[1] by usage level. As mentioned, the higher usage customers pay more than the average increase of 3.2%, with lower usage levels receiving less than the 3.2% increase.

For Rate 110, the additional revenue needed will be recovered during the four summer months. For Rate 115, the additional revenue needed will be recovered during the eight non-summer months. As a result, customers on Rate 110 would see a higher impact on their bill during the summer months. To smooth the impact across the year, OPPD will refer customers to level bill options to avoid having to realize the impact during the summer months.

**RATE 110: Bill Impact Based on Monthly kWh Consumption**

| | Summer | | | Non-Summer | | Annual | | |
|---|---|---|---|---|---|---|---|---|
| Monthly kWh Consumption | Current Bill | Bill Change $ | Bill Change% | Current Bill | Bill change % | Current Bill | Bill Change $ | Bill Change % |
| 500 | $77.73 | $4.45 | 5.7% | $69.40 | 0.0% | $866.12 | $17.80 | 2.1% |
| 1,000 | $125.46 | $8.90 | 7.1% | $107.63 | 0.0% | $1,362.88 | $35.60 | 2.6% |
| 1,500 | $173.19 | $13.35 | 7.7% | $134.91 | 0.0% | $1,772.04 | $53.40 | 3.0% |
| 2,000 | $220.92 | $17.80 | 8.1% | $162.19 | 0.0% | $2,181.20 | $71.20 | 3.3% |
| 2,500 | $268.65 | $22.25 | 8.3% | $189.47 | 0.0% | $2,590.36 | $89.00 | 3.4% |
| 3,000 | $316.38 | $26.70 | 8.4% | $216.75 | 0.0% | $2,999.52 | $106.80 | 3.6% |

[1] Bill impact includes the customer service charge, FPPA, and energy charges. It does not include sales tax.

RATE 115: Bill Impact Based on Monthly kWh Consumption

| | Summer | | Non-Summer | | | Annual | | |
|---|---|---|---|---|---|---|---|---|
| Monthly kWh Consumption | Current Bill | Bill Change% | Current Bill | Bill Change $ | Bill change % | Current Bill | Bill Change $ | Bill Change % |
| 500 | $77.73 | 0.0% | $69.40 | $1.95 | 2.8% | $866.12 | $15.60 | 1.8% |
| 1,000 | $125.46 | 0.0% | $103.85 | $4.07 | 3.9% | $1,332.64 | $32.54 | 2.4% |
| 1,500 | $173.19 | 0.0% | $126.33 | $6.72 | 5.3% | $1,703.40 | $53.74 | 3.2% |
| 2,000 | $220.92 | 0.0% | $148.81 | $9.37 | 6.3% | $2,074.16 | $74.94 | 3.6% |
| 2,500 | $268.65 | 0.0% | $171.29 | $12.02 | 7.0% | $2,444.92 | $96.14 | 3.9% |
| 3,000 | $316.38 | 0.0% | $193.77 | $14.67 | 7.6% | $2,815.68 | $117.34 | 4.2% |

### c) Small General Service

The small general service class consist of three rates – Irrigation Service (Rate 226), General Service Non-Demand (Rate 230), and General Service – Small Demand (Rate 231).

The small general service class will see an average proposed increase of 0.9%. The lower increase is a result of several factors. Growth in customer acquisition in the residential class outpaces that of the small general service class. Although distribution and customer-related costs increased, having more residential customers than small general service resulted in a larger allocation of these costs to residential over small general service. Moreover, while the small general service class has higher load factors, a measure of energy efficiency, than that of the residential class, it does not have the energy needs of the large general service class. Exiting the no general rate increase, the changes in costs do not disproportionately affect the small general service class.

The small general service class has our most diverse customer consumption class in Rate 231, which captures all customers between 50kW and 1,000kW. Customers around 50kW have attributes more similar to that of the residential and small general service class whereas customers near the 1,000 kW display characteristics more similar to that of large general service customers. Further analysis on this rate structure as well as the customer consumption profiles will be conducted in the future to ensure this rate's structure matches the customers' needs and usage.

#### i) Cost Drivers

The costs affecting the small general service class are the same as the residential, but to a lesser extent. The class experienced increasing distribution and customer-related costs, and decreasing demand related production costs. Therefore, the small general service class represents a smaller apportionment of the overall average 2.5% increase.

#### ii) Rate Changes

We do not propose a change in Rate 226 at this time. Currently, Rate 226 revenues are collected through an energy charge and horsepower charge. This horsepower component is unique to this rate, and is charged only during the three summer months. OPPD would like to gather customer feedback from irrigation customers to determine whether this design characteristic is desirable. Irrigation customers also present a unique challenge as their energy needs for irrigation typically coincide with our system peak. Thus, load reduction possibilities through product offerings could significantly improve both costs and rate design elements.

Both Rate 230 and Rate 231 receive the same, average 0.9% increase because the customer characteristics are similar. Both rates recover production demand-related costs through the energy component in the summer rates. The summer energy rate increases represent a movement towards cost of service in the recovery of production demand costs in the summer energy charge. This increase sends the correct price signal during the summer, encouraging conservation during the summer months.

Rate 231 did not receive an increase in the demand charge. As mentioned, Rate 231 is our most diverse rate class with customers spanning from the minimum demand of 50kW to 1,000kW a month. With such a diverse customer class, changes to the demand component will be best approached gradually. Furthermore, the cost of service results show that the production demand costs recovered during the summer needed an increase that merited the energy charge increase during the summer months. The winter energy charge reflects a revenue neutral increase with the second charge needing to be increased to recover the energy-related variable costs of that component.

| Rate | Billing Components | Current Rate Summer | Current Rate Non-Summer | Proposed Rate Summer | Proposed Rate Non-Summer |
|---|---|---|---|---|---|
| 226 | Annual Charge Per Horsepower | | | | |
| | Single-Phase | $17.94 | | $17.94 | |
| | Three-Phase | $24.06 | | $24.06 | |
| | Energy Usage | 11.07 ¢/kWh | | 11.07 ¢/kWh | |
| 230 | Energy Usage | | | | |
| | 0 - 1000 kWh | 9.11 ¢/kWh | 7.89 ¢/kWh | **9.78 ¢/kWh** | 7.89 ¢/kWh |
| | 1001 - 3000 kWh | 8.40 ¢/kWh | 7.89 ¢/kWh | 8.40 ¢/kWh | 7.89 ¢/kWh |
| | 3001+ kWh | 8.40 ¢/kWh | 5.24 ¢/kWh | 8.40 ¢/kWh | 5.24 ¢/kWh |
| 231 | Demand Per kW | $5.38 | | $5.38 | |
| | Energy usage | | | | |
| | First 300 kWh/kW of demand | 7.38 ¢/kWh | 6.10 ¢/kWh | 7.38 ¢/kWh | **5.93 ¢/kWh** |
| | All additional kWh | 5.00 ¢/kWh | 3.75 ¢/kWh | **5.81 ¢/kWh** | **4.50 ¢/kWh** |

### iii) Bill Impact

Bill impacts for Rate 230 were rather uniform, with the largest yearly impacts to customer bills of less than 2%, according to 2019 consumption data. Customers on Rate 230 will only experience a change in their summer bill. The maximum increase in a month will be $6.70. The table below shows the impact at different consumption levels.

**RATE 230: Bill Impact Based on Monthly kWh Consumption**

| | Summer | | | Non-Summer | | Annual | | |
|---|---|---|---|---|---|---|---|---|
| Monthly kWh Consumption | Current Bill | Bill Change $ | Bill Change% | Current Bill | Bill change % | Current Bill | Bill Change $ | Bill Change % |
| 200 | $51.59 | $1.34 | 2.6% | $49.15 | 0.0% | $599.58 | $5.36 | 0.9% |
| 500 | $79.48 | $3.35 | 4.2% | $73.38 | 0.0% | $904.96 | $13.40 | 1.5% |
| 1,000 | $125.96 | $6.70 | 5.3% | $113.76 | 0.0% | $1,413.92 | $26.80 | 1.9% |
| 2,000 | $211.82 | $6.70 | 3.2% | $194.52 | 0.0% | $2,403.44 | $26.80 | 1.1% |
| 3,000 | $297.68 | $6.70 | 2.3% | $275.28 | 0.0% | $3,392.96 | $26.80 | 0.8% |
| 4,000 | $383.54 | $6.70 | 1.7% | $329.54 | 0.0% | $4,170.48 | $26.80 | 0.6% |

Rate 231 has both customers with a decrease in bills (those customers who do not reach the second tier energy charge) and customers with larger increases. The rate increase was determined as a movement towards cost of service with a gradual transition within the rate class. Further analysis will be conducted on this rate structure as well as the separation of customers based on their consumption profiles.

### d) Large General Service Rate Changes

The large general service class consists of Rate 232, 240, 245, 250, 261, and 261M. The large general service class will also see a larger increase than the average overall 2.5% increase at an average of 3.2%. While distribution and customer-related costs largely do not affect the large general service class, the increases in energy-related costs and transmission costs has led to the needed increase for the large general service class. Generally, the large general service class rates will see a decrease in the demand component and increase in energy component. Moreover, while in the past we have provided several rates at differing levels of demand, the large general service class has grown to be more homogenous in system utilization. Consequently, there is a general convergence of the large general service rates. One rate offering, Rate 240, which currently serves no customers, will be retired.

#### i) Cost Drivers

As mentioned, energy-related costs have increased since our last rate adjustment while demand-related costs have decreased. Having a high load factor, which measures energy efficiency, results in a relatively smaller share of production demand-related costs allocated to the large general service class. However, their large usage of energy results in more energy-related costs being allocated to the large general service class. Exiting the no-general rate increase, OPPD has a different composition of energy and demand related costs and requires a realignment of the demand and energy components of our large general service class rates. As new generation assets are added we will continue to update our energy and demand components in the coming years.

#### ii) Rate Changes

As mentioned, the demand components are generally downward trending in the large general service rates with energy-related costs increasing.

With respect to Rate 232, the demand component historically did not recover all demand-related costs. Rather, the higher energy charge recovered some of the fixed demand-related costs. To properly align the demand rate with the COS study, we propose increasing the demand charge while simultaneously removing the seasonal distinction in the energy charge. This realignment better coordinates Rate 232 with our other large general service offerings.

The differences between Rates 245, 250 and 261 has narrowed from the 2016 rate structure according to the cost of service. Rate 261s demand charge remained lower than that of Rate 250 and 245 reflecting that customers at this class are receiving power at the 161kV level. As a result, demand-related transmission and distribution costs are lower.

Our 261M rate offering decreased in the demand charge as our production demand charges have decreased since our last rate case. Furthermore, the tariff requirements for 261M, a market participant for energy, excludes the energy-related generation costs.  This marginal decrease in rate reflects realignment of rates after the no general rate increase to reflect changes in cost structures.

| Rate | Billing Components | Current Rate Summer | Current Rate Non-Summer | Proposed Rate |
|---|---|---|---|---|
| 232 | Demand Per kW | $10.17 | | **$11.65** |
| | Energy usage | | | |
| | First 300 kWh/kW of demand | 5.55 ¢/kWh | 4.12 ¢/kWh | |
| | All additional kWh | 5.04 ¢/kWh | 3.60 ¢/kWh | |
| | All kWh | | | **4.49¢/kWh** |
| 240 | Demand Per kW<br>Energy Usage | $13.49<br>4.01 ¢/kWh | | **Eliminate Rate** |
| 245 | Demand Per kW<br>Energy Usage | $14.28<br>3.57 ¢/kWh | | **$13.47**<br>**3.97 ¢/kWh** |
| 250 | Demand Per kW<br>Energy Usage | $14.28<br>3.45 ¢/kWh | | **$13.47**<br>**3.91 ¢/kWh** |
| 261 | Demand Per kW<br>Energy Usage | $12.66<br>3.40 ¢/kWh | | $12.66<br>**3.76 ¢/kWh** |
| 261M | Demand Per kW<br>Energy Usage | $22.45<br>Market Energy | | **$21.51**<br>Market Energy |

### iii) Bill Impacts

With less than 150 large, general service customers, our account executives will execute communication of the rate changes to each of the customers and potential bill changes based on usage history. Communication among our large general service class remains at a highly personalized level.

### e) Lighting

The lighting class consists of Street Lighting (Rate 350), Traffic Signals (Rate 351), and Private Outdoor Lighting (Rate 236). Lighting has been in a transformative stage the past several years. OPPD collaborated with its streetlight customers to convert high-pressure sodium and mercury vapor fixtures with more efficient LED fixtures. In 2019, OPPD began this initiative to invest approximately $25 million in this effort. The program will be roughly 75% complete by the end of 2021. This investment not only reduced the maintenance costs with LED fixtures, but also saved our customers from having increased energy needs during which time energy-related costs have grown. This partnership has both reduced our long-term investment in streetlight maintenance while also reducing customers' bills.

#### i) Cost Drivers

For Lighting, there is an increase in energy-related costs. In addition, lighting customer also benefit from investments in the distribution system and consequently these customers will experience an increase in their rates. Despite the reduction in energy usage due to the movement towards LED fixtures, the COS study determined that this class requires additional revenue to be recovered.

#### ii) Rate Changes

The average 2.5% increase will be assessed across all method codes and streetlight offerings as well as traffic signals and private outdoor lighting.

### f) Municipal Service

The municipal service rate, Rate 357, is offered to municipal utilities. These customers maintain their distribution system after the point of delivery. With distribution costs assumed by the municipal utility, investments made to distribution facilities at lower levels than that of which wholesale towns are receiving power are not allocated to this class. Due to the unique characteristics, changes in costs to serve those on Rate 357 are nominal. As a result, we do not propose an increase to the rate components at this time.

## G) Biennial Rate Package Items

In early 2020, the Executive Leadership Team along with Board of Directors Finance Committee members, aligned on what is now referred to as the Biennial Rate Package. This package outlines the work of the rates team for a two-year period. Acknowledging that rate work will continue to come up within the two years, this process prioritizes the work that the Pricing and Rates group should focus on. As new items come up in discussion, the Finance Committee and the Executive Leadership Team will discuss prioritization and if changes needs to be made. For the first Biennial Rate Package to be submitted in 2021 to be effective in 2022 the following items were identified:

- Fuel and Purchased Power Adjustment Modernization
- Declining Energy Blocks
- Sports Field and Fairground Service

- Rider 469W: Waiver Option
- Net Metering Change
- Green Power Refresh
- Standby for Intermittent Renewable Generation

### a) Fuel and Purchased Power Adjustment Modernization

OPPD collects the annual revenues required to cover the variable costs associated with power production and acquisition through its Fuel and Purchased Power Adjustment (FPPA) Base Rate and the FPPA Factor. The FPPA Base Rate is included in the general rate and the FPPA Factor is an adjustment billed in addition to the general rate. The District is updating the FPPA formula to include off-system sales, starting on January 1, 2022. Including off-system sales will provide more stability to the over and under collected amounts on an annual basis in the future when the market experiences high volatility in fuel and energy prices.

The proposed formula effective January 1, 2022 is:

$$FPPA = \frac{NEC-O}{S} - F$$

Where:

| | | |
|---|---|---|
| NEC | = | Annual Budgeted Net Energy Costs= (FC + C + PP – OSSR) |
| FC | = | Fuel Costs *(Fuel costs incurred to support the generation of electricity)* |
| C | = | Consumables *(Materials used or depleted as part of the Generating process and vary with each kilowatt-hour produced.)* |
| PP | = | Purchased Power Costs *(Costs from Southwest Power Pool transactions associated with purchase of power.)* |
| OSSR | = | Off-System Sales Revenues *(Revenues from SPP transactions associated with off-system sales.)* |
| O | = | Over/Under Balance<br>*For any given period, the Over/Under Balance is the difference between the actual net energy costs and the revenue generated by the FPPA Base Rate plus the FPPA Factor in effect during the period.* |
| S | = | Annual Budgeted Energy Sales *(Budgeted kilowatt-hour sales to retail and municipal service customers)* |
| F | = | Fuel and Purchased Power Base Rate<br>*The portion of the energy charge component of the applicable OPPD Rate Schedules that recovers the net costs of fuel, purchased power, off-system sales and related consumable* |

*costs. For all applicable Rate Schedules, the Fuel and Purchased Power Base Rate is 1.606 cents per kilowatt-hour.*

For 2022, the FPPA Factor will remain at 0.186 cents.

### b) Declining Energy Blocks

The Finance Committee asked OPPD to examine the impact of removing the declining energy blocks in the non-summer months for Residential Standard Rate 110. In June 2020, a cross-functional team was formed to perform the analysis following OPPD's Product Development Framework, taking a holistic product-level approach to exploring the issue compared to the normal framework needed to organize and manage a pure rates project. The process included:

- **Concept Phase** - Developing the problem statement and vision
- **Research Phase** - Examined the current state and researched past rate changes and performed industry analysis and market research
- **Analysis Phase** - Data analysis and segmentation of impacted customers and evaluated rate alternatives and product options
- **Develop Phase**
- **Launch Phase**

During the Research Phase, external focus groups met to determine customer perceptions around the residential rate structure and implications of potentially transitioning away from the declining energy blocks. OPPD also conducted external pricing focus groups to talk through the concept of value expressed through various pricing models, and to determine elements/characteristics that comprise feelings of value. An internal employee workshop was also completed to explore and ideate future rate opportunities and focus on creating collaboration between OPPD and our customers.

The initial opinions regarding the declining energy blocks were that it gives the perception that this rate structure encourages increased consumption and that removing the declining energy blocks will only impact larger homes that use more and therefore should pay more. However, after thorough analysis was completed on impacted customers using customer usage data, customer information and property attributes, three findings started to emerge through the data:

- Older, smaller, less-efficient homes will be affected just as much as larger homes.
- Demographic data show larger homes, but there are still vulnerable customers affected.
- A change in blocks with no alternative offering will negatively impact all-electric customers by sending an inconsistent price signal that may discourage electrification.

Based on the findings through the analysis, the recommendation was to defer removing the declining energy blocks and pursue a more robust and comprehensive review of the

Residential and Small Commercial Rates. This is discussed further in the **Future Focus** section on where OPPD is moving towards.

### c) Sports Field and Fairgrounds Service

The current Sports Field and Fairground Service receives the benefit of the demand charge not ratcheting for the following 11 months. This service has previously been offered to customers that meet the following qualifications:

- Pay, upfront, the total cost of the line extension required to provide the service
- Be tax supported governmental institutions
- Operate seasonal service to an outdoor sports field or fairground installation (where lighting constitutes the majority of the energy consumption)
- Connected Load does not exceed 300kW

In a review of the Sports Field and Fairground Service, it was determined that this type of service incurs the same costs as a customers on Rate Schedule 231- General Service Small Demand. Therefore, to adhere to the fair, reasonable, and non-discriminatory state statute, the Sports Field and Fairground Service will no longer be available on January 1, 2022, and customers will be converted to Rate Schedule 231- General Service Small Demand. A letter has been sent to the customers taking service under the Sports Field and Fairground Service with their OPPD representative's name and phone number to discuss impact of this change and potential rider options available if applicability is met.

### d) Rider Schedule 469W: General Service Time of Use- Waiver Option

Rider Schedule 469W is restricted to customers served under this rider schedule on or before January 1, 2013. This type of rate structure is not consistent with current rate-making standards in light of OPPD's membership in the Southwest Power Pool and its integrated market. In June of 2021, in Board Resolution 6441, the Board of Directors approved that Rider Schedule 469W be removed as an available rider option as of June 01, 2022.

### e) Net Metering Changes

In June and August of 2021, OPPD updated the applicability to Rider Schedule 483-Net Metering to clarify the current language and increase the kW limit. Rider Schedule 483 previously stated:

"*DG systems qualifying for Rider Schedule 483 shall not exceed 25kW in either the aggregate system AC nameplate capacity or aggregate system DC nameplate capacity, as determined by OPPD during the DG application and approval process.*"

OPPD received customer feedback on the capacity limitations specifications with regard to net metering and clarified that the size limitation applied to the AC inverter. In addition, to allow more personalized energy choices to customers, the applicability has been changed to:

*"DG systems qualifying for Rider Schedule 483 shall not exceed 100kW in the aggregate system AC nameplate capacity, as determined by OPPD during the DG application and approval process."*

This update was made effective September 1, 2021 through Board Resolution 6457.

### f) Green Power Refresh

Rider Schedules 463A- Residential Green Power and 463B- Commercial Green Power, were introduced in 2002. These funds were used to support renewable generation projects. With expansion of renewable generation occurring at such a large level, the Green Power Riders were no longer meeting customers' needs or OPPD's goals.

OPPD's Product Development and Marketing team led the Green Power Refresh. As part of this initiative, industry research was gathered on what products and services are offered by other utilities. Customer outreach was conducted to help understand what OPPD customers value, discuss product features and benefits, and test product ideas to receive and incorporate feedback. The final result of this initiative found that the Green Power Refresh would be best received if the funds were used for community projects. Also, the research found that these community projects would best be received when the project led to increased community involvement and were transparent with the funds and project selection.

Taking all feedback into account, the team recommended sun-setting the current Green Power Riders and offering a new product. The new product will allow customers to subscribe to a green-focused program and partner with OPPD to choose, promote and execute on environmental projects that educate our community members and builds a healthier, safer and cleaner environment.

Riders 463A and 463B will no longer be available as of March 31, 2022 and will be part of the Board Resolution for Rate Action and Corporate Operating Plan approval in December, 2021.

### g) Standby for Intermittent Generation

In June 2020, in Board Resolution 6377, Rider Schedule 464-Standby Service was revised to include:

*"This Rider Schedule is not mandatory for Customer-owned renewable energy equipment."*

The revision to Rider Schedule 464- Standby Service was updated because this rider was not designed to capture the intermittency of non-dispatchable generation resources such as solar and wind energy equipment. It was also stated that OPPD will continue to analyze the impacts of customer solar and wind generation equipment to assure that the cost of service to such customers is adequately recovered in accordance with generally accepted rate principles and Strategic Directive 2, relating to the equitable assignments of costs across and within all customer classes.

OPPD will continue to analyze the impacts of customer-owned, intermittent renewable generation in 2022 to ensure costs are adequately recovered and not impacting non-generating customers.

### H) Outreach and Education

OPPD is committed to engagement, education and transparency around our rates process. With the proposed rate increase, OPPD will be able to cover rising material and labor costs, invest in new technology, and modernize the electric utility for the future.

We understand that some customers desire a deeper understanding. With that, OPPD offers opportunities to meet stakeholders where they are - to provide more information and address questions related to rates and the 2022 Corporate Operating Plan.

OPPD's speakers bureau, combined with a communication plan (i.e. social media, emails, etc.), and direct contact with large customers and key stakeholders, means we will be able to share information about assistance programs and other ways customers can help control their utility costs.

The work of educating and communicating with customers does not end with the presentation of the 2022 Corporate Operating Plan. OPPD plans to continue these efforts well into 2022 to help customers adjust to the rate changes in their bill.

### I) Future Focus

The Future Focus section of this report is mentioned throughout. While still in conceptual design, OPPD is in the process of planning an intelligent energy ecosystem. The ecosystem is designed to enhance both the customer experience and product development by encouraging innovative solutions to address the emerging complexities of a future less dependent on baseline generation. The intelligent energy ecosystem considers the implementation of AMI metering, coordination of customer profiles and usage data, and engagement strategies to align and promote OPPD offerings with customer preferences.

#### i) Reliability and Customer Preference

Reliability is the number one concern of customers. The hurricane-strength wind storm of July 2021 reminds us of the importance of reliability to customers and the need for a utility to prioritize it. According to the latest employment statistics from the U.S. Bureau of Labor, 13.2% of employed persons remain as teleworkers due to the coronavirus pandemic. This makes reliability for these customers more highly valued than ever before.

While reliability is the most valued attribute of a utility, meeting customer preferences is also an integral part of providing exceptional utility service in the 21st century. Customer engagement has always been a high priority for OPPD. However, customer preferences have become even more diverse than in decades past. Customer-owned generation, electrification of cars, provisioning of environmentally sensitive energy services all represent consumer preferences that have changed in the transformation of how our customers utilize electricity.

The goal of the intelligent energy ecosystem is to both increase reliability and coordinate data collection to better meet our customer's needs and preferences.

In conducting the outreach related to the removal of the declining non-summer blocks, remarkably diverse opinions were seen. This effort revealed the truth about how much our customers desire to engage in the subjects of rate education and the shaping product offerings. Through a more technologically advanced grid modernization, we anticipate a greater participation from the customer in helping support the capacity, reliability and energy needs of OPPD.

(1) Outage notification

Take the example of outage notification as a solution combining the customer need for increased reliability and OPPD's pursuit of an intelligent energy ecosystem to move the customer experience forward.

With advanced metering infrastructure (AMI) technology, OPPD will no longer have to worry or guess if any of our customers are in the dark without our knowledge. The AMI technology would provide us with data identifying customers who are without power, meaning OPPD will no longer have to rely on customers to report outages. Not only will this increase the timeliness of restoring power but it will also enhance our customer's faith in OPPD's service.

(2) Usage Notification

Another benefit of an intelligent energy ecosystem is two-way customer communication. Creating customer notification of changes in usage patterns, including on-peak usage or other important usage characteristics, will allow customers to know in near real-time how their consumption is affecting their monthly bill. In anticipation of three-part rates, customer's will need awareness of their on-peak or off-peak usage, or how large sudden increases in usage or shifting of usage patterns will impact their bill.

i) Additional Product Offerings

With the ability to collect and coordinate customer data with an intelligent energy ecosystem, OPPD will be able to recommend and match customers with product offerings that best suit their needs. As we move our future towards a generation mix of renewables, supplemented by peaking generators, customers with flexible demand, such as controllable electric water heaters or dispatchable battery power from electric cars, will become some of our most beneficial customers and aid OPPD in grid operations. In return, these customers will benefit by taking advantage of riders, incentives and product offerings. Knowing whether a customer has an electric vehicle or electric water heater will greatly increase the ability to communicate with our customers who might want to take advantage of product offerings.

### ii) AMI and the Transitional Phase

Most of the changes discussed here require the acquisition of AMI technology to enable rate structures, and product offerings to complement how customers utilize the system. Even if AMI is adopted, it will require a transitional phase before it is fully implemented, and customers and OPPD can take full advantage of the benefit.

During this transitional phase, customer, energy and demand charges will be aligned to position customers with price signals that would align with renewable integration and promote cost containment. All customer impacts would need to be considered, modeled and evaluated, including gathering customer sentiments to help determine an optimal interim rate strategy for our customers.

Altogether, the adoption of an intelligent energy ecosystem would integrate customer information with system costs and utilization to allow for a more congruent partnership between OPPD and its customer-owners. The results will provide customers with greater flexibility and choice, while also allowing better alignment of cost for customers based on their load profile and flexibility.

For more information regarding rates, as well as OPPD's Corporate Operating Plan, please visit oppd.com.