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OPPD
Omaha Public Power District

Rate Fundamentals Report

Disclaimer

The statements made reflect OPPD's opinion and are intended strictly for educational purposes. The materials are intended to provide transparency in rate design and fundamental cost-of-service principles utilized in rate setting by OPPD. Some examples have been simplified for accessibility.

Agenda

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I. Introduction

Introduction
Report Goal

OPPD wants our customers to have foundational knowledge of how their rates are structured. This report provides information on how rates are calculated, set annually, and designed to align customer expectations and OPPD's strategic vision. This report connects the Corporate Operating Plan (COP), Strategic Initiatives, and Cost of Service Study (COSS) to help customers understand how these work together in establishing rates.

The following represents the goals of the information contained within this report:

- Introduce electricity basics
- Provide information on OPPD's Total Cost Determination (also referred to as the Revenue Requirement)
- Illustrate the steps performed in an embedded COSS with visibility to key modeling decisions
- Discuss alignment of costs with the fundamental rate elements – demand, energy, and service charges
- Bring visibility to OPPD's strategic vision for rate design
- Provide the Total Cost Determination from the 2022 General Rate Action in functional, classified, and allocated components

Introduction

Overview of the Rate Process

How large is the pie?

Total Cost Determination

- Determine the total costs required to provide service to our customers.

How to slice the pie?

Cost of Service Study

- Assign the total costs based on the relative contribution of each customer class to the cost drivers.

How to serve the pie?

Rate Design

- Recover the costs with rates that adhere to generally-accepted rate principles.

Introduction
Key Terms and Definitions

Generation	The production of energy via coal, natural gas, and renewables to satisfy peak demand and energy needs of our customers.
Transmission	Transmission of energy via high-voltage supply facilities, power lines, and substations that bring power from the generation source into our service territory.
Distribution	Distribution of energy via facilities and wires that connect the supply of energy to our customers.
Customer Services	Support services for all customers regardless of energy consumption (i.e. billing, metering, data management, customer service, etc.).

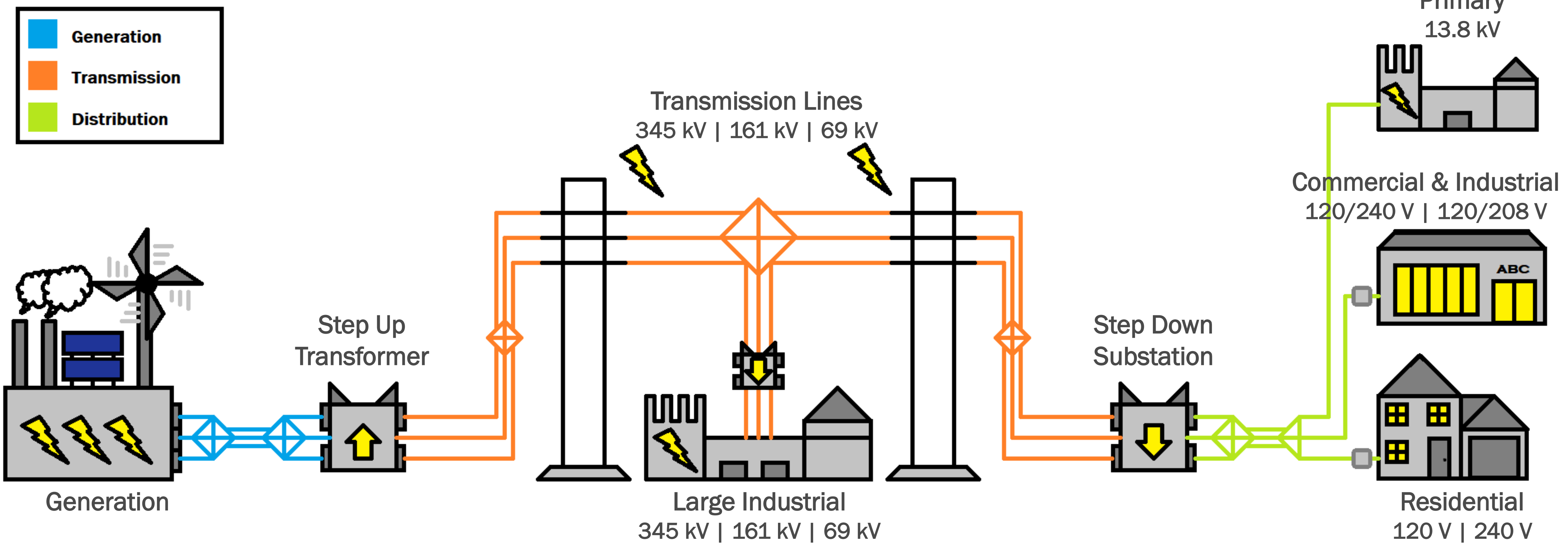
Introduction
Key Terms and Definitions

Cost of Service	The process of fairly apportioning the total costs to each customer class based on the relative proportion of their contribution to the costs.
Total Cost Determination	The total cost determination ensures that revenues cover the total costs to serve our customers and support our operations. This is also referred to as the Revenue Requirement.

Introduction
Key Terms and Definitions

Demand Costs	Costs based on the customer's highest amount of power (demand), measured in kilowatts (kW).
Energy Costs	Costs based on the customer's cumulative energy needs, measured in kilowatt-hours (kWh).
Customer Costs	Costs based on the number of customers on the system, measured in customer-months.

Introduction
The Electric Delivery System



<u>Illustration based off of the following source:</u>
Office of Electricity Delivery and Energy Reliability. (2015, July). *United States Electricity Industry Primer*. U.S. Department of Energy. Retrieved January 2023, from https://www.energy.gov/sites/prod/files/2015/12/f28/united-states-electricity-industry-primer.pdf

Introduction

Electricity Basics: Generation

- Generation is the conversion of energy resources into electricity.
- Energy resources include coal, gas, renewables, and other forms.
- Each energy resource has a different ability to meet various energy needs and usage.
- Resource planning decisions include evaluating load growth expectations, resource adequacy, system resiliency, and cost effectiveness, while also taking into consideration OPPD’s Pathways to Decarbonization.

Introduction

Electricity Basics: Generation by Source

- Fuel source is an important factor in generation.
- Fuel sources are typically categorized as renewable vs non-renewable.
- As outlined in the strategic visions of the *Powering the Future to 2050*, OPPD has a net carbon zero goal for 2050.
- As of 2023, OPPD's nameplate capacity consisted of 27.4% wind resources.

Introduction

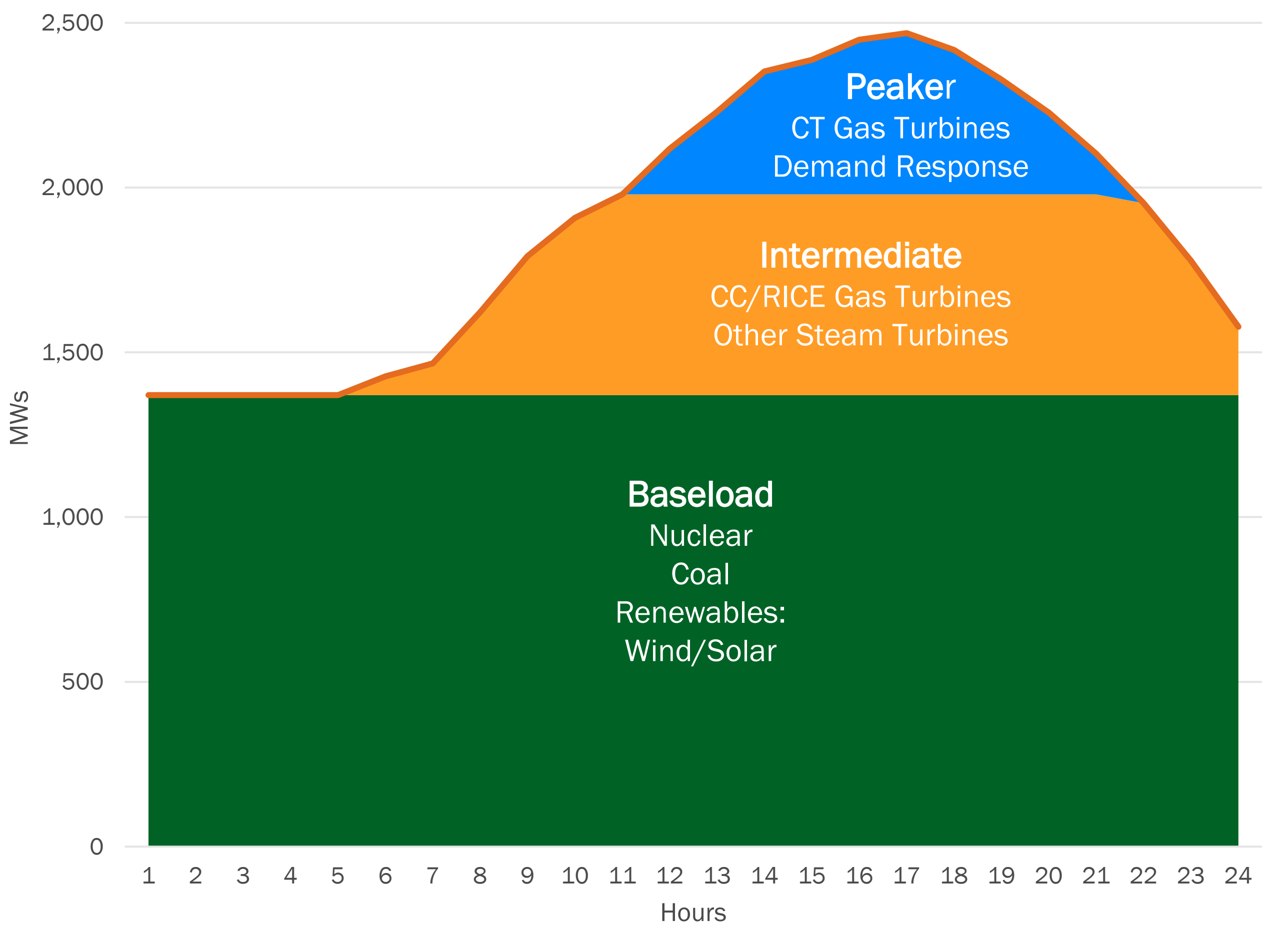
Electricity Basics: Generation by Flexibility

- Dispatchable refers to the ability for a generation resource to change its output based on demand (within its generation potential).
- Dispatchable firm resources include technologies like conventional coal thermal, gas-fired combined cycle and combustion turbine, nuclear, geothermal, biomass, and others.
- Some renewable technologies are fully dispatchable such as nuclear and geothermal, while others such as wind and solar are dispatchable but limited to their variable fuel supply (referred to as variable energy resources).
- The ability to control generation output is critical for resiliency as severe weather, localized grid emergencies, and other extreme events can impact customers.
- OPPD’s resource planning mix balances the ability to withstand and recover from localized and regional events with securing energy resources and maintaining a diverse portfolio of assets.

Introduction

Electricity Basics: Generation by Usage

- Generation facilities are often categorized by their intended purpose and utilization into the following usage categories:
- **Baseload** refers to facilities that are intended to run around the clock. Baseload units serve the minimum level of demand on the electrical grid over all hours of the day. Typically, these facilities have low fuel costs, but are less flexible to variations in demand.
- **Intermediate** refers to units that run a substantial portion of the year, but not the whole year. Combined-cycle gas units have historically filled this role.
- **Peaker** refers to units that are only utilized during peak hours. Typically, these units have higher fuel costs or economic costs, such as demand response.



Disclaimer on Peaker Resources:
Peaker Resources have historically operated as strictly serving peak load as the name would suggest.
However, Peaker Resources currently operate as both serving peak load and balancing renewable resources.

Introduction
Electricity Basics: Transmission

- The transmission system is comprised of high-voltage lines (69kV, 161kV, & 345kV) that transfer bulk electricity between generation facilities and the end customer.
- Transmission lines are typically above ground with large support towers.
  - Air acts as the insulator with higher voltages requiring larger clearance.
  - Higher voltages reduce line losses.
- Some of the largest customers interconnect at the transmission level.
- For resiliency, each load point on the system generally has at least two alternate supply sources.

Introduction

Electricity Basics: Transmission (Cont.)

- OPPD's transmission system interconnects both to its generating stations and to neighboring utilities.
- OPPD's transmission system is part of the Eastern Interconnection and is a part of the Southwest Power Pool (SPP).
- SPP oversees regional transmission expansion for the OPPD region and guides the transmission service processes within our service territory.
- Altogether, the interchange of power over the transmission system has oversight by several national and regional entities that help ensure the reliability of the transmission system.

Introduction
Electricity Basics: Distribution

- The distribution system receives power from the transmission system.
- This power is brought down from high-voltage levels through distribution substations to a level that can be used by households and businesses.
- Most customers take service at the distribution level.
  - Primary Level – e.g. 13.8 kV (Three Phase) & 8 kV (Single Phase)
  - Secondary Level – e.g. 120V/240V or less than 600V
- The distribution system consists of the poles, transformers, substations, meters, service drops, and other assets needed to connect service to customers.

II. Total Cost Determination

Total Cost Determination

Covering our Costs to Serve

- The total cost determination ensures that revenues cover the costs to serve our customers and support our operations, which is commonly referred to as the **Revenue Requirement.**
- The total cost determination is established by Strategic Directive 3 (SD-3), which provides the guiding principles to maintaining a low-cost, flexible structure to support the operation of the utility.
- The main principle established in SD-3 is maintaining a minimum 2.0 Debt Service Coverage Ratio.

$$\text{Debt Service Coverage Ratio} = \frac{\text{Revenues} - \text{Expenses}}{\text{Debt Interest} + \text{Principal Payments}}$$

Total Cost Determination
Capital Expenditure Philosophy

- The Debt Service Coverage Ratio is an important metric in evaluating the health of the utility.
- Maintaining the 2.0 Debt Service Coverage Ratio contributes to OPPD preserving a AA credit rating with the credit rating agencies.
- It ensures that new debt will be issued at competitive bond rates, which lead to lower long-term electricity rates for our customers.
- While Debt Service Coverage is an important consideration, there are other metrics that credit rating agencies consider when evaluating the bond rating. Likewise, OPPD’s capital expenditure philosophy and investment decisions extend beyond credit rating agency evaluations.
- When making resource decisions, OPPD considers many factors such as reliability, economic development, competitive rate position, cost, etc.

Total Cost Determination
Return on Investments

- While OPPD does not set a minimum return on its investments on behalf of its customers, OPPD is required by state statute to set rates sufficient to establish and maintain a successful operation that does not incur operating losses (Nebraska Revised Statute 70-655).
- As a publicly-owned utility, any earnings above operating costs are strictly to ensure debt obligations are sustainably funded and investments are not deferred to future customers. Thus, returns are utilized to meet the needs of current customer-owners and support of operations.

Total Cost Determination
Strategic Investments

- OPPD is entering one of the most transformative resource planning eras in its 75-year history as capacity and energy needs grow and the industry evolves.
- OPPD's service territory is experiencing rapid growth in energy needs due to our competitive rates and economic development.
  - For example, peak load increased from 2,545 MW in 2022 to 2,789 MW in 2023
- Additionally, OPPD is foundationally changing its resource portfolio as it moves towards it's 2050 net-zero carbon goal.
- OPPD's Near Term Resource Planning Goals support:
  - 1,000 – 1,500 MW of wind and solar
  - 125 MW of battery storage
  - 32+ MW of demand response
  - 600 – 950 MW of combustion turbines
  - 320 MW of added fuel capacity and fuel oil storage

Total Cost Determination
Planning Process Considerations

While the Integrated Resource Plan (IRP) details the comprehensive work in determining the resource planning strategy, several key considerations are listed below.

Access to Credit Markets	Reliability and Resiliency	Cost Minimization	Environmental Sensitivity
Competitive Rate Position	Economic Development	Customer Experience	Strategic Alignment

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Total Cost Determination

Putting It All Together

- The total cost determination supports the overall needs of our system and ensures OPPD's operations remain favorable to credit rating agencies for the issuance of debt to finance investments.
- The total cost determination is driven by the standard established in SD-3 to maintain a minimum 2.0 Debt Service Coverage Ratio.
- OPPD's capital expenditure philosophy ensures that a balanced approach is taken regarding resource decisions to secure access to credit markets, maintain competitive rates, and support the overall health of the system.

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III. Cost of Service

Cost of Service
Embedded Cost of Service Study

- After the Total Cost Determination is complete, we move to the Cost of Service Study (COSS).
  - Total Cost Determination – *How large is the pie?*
  - Cost of Service Study (COSS) – *How do we slice the pie?*
- OPPD utilizes an embedded-cost approach, which is the most common approach in the industry.
- An embedded-cost approach utilizes accounting costs associated with assets and expenses as they occur to provide service.

Cost of Service
Study Goals

- Nebraska Revised Statute 70-655 requires the Board to establish rates that are fair, reasonable, and non-discriminatory.
- The goal of the COSS is to fairly apportion the total costs to each customer class based on the relative proportion of their contribution to those costs.
- There are three fundamental steps in performing an embedded COSS:
  - Functionalization
  - Classification
  - Allocation
- For each fundamental step, the COSS seeks to determine cost causation to appropriately assign costs to each rate class.
  - i.e. What was the cost driver?

Cost of Service
Overview

- The COSS goes through functionalization, classification, and allocation to ensure the costs of providing service are fairly and reasonably apportioned.
- Functionalization separates the utility's assets according to how they are used – generating electricity to meet demand and energy needs, transferring electricity from the power source to the distribution system, and distributing the power to OPPD's customers' premises. Billing and metering is included in distribution.
- Classification provides measures for the service level of each of the functionalized components.
  - Customer demand is measured in kilowatts (kW),
  - Customer energy is measured in kilowatt-hours (kWh)
  - Customer counts are measured in the number of customers (can be a weighted measure)
- Allocation then applies the classification metrics to each rate class.

Cost of Service
Step 1: Functionalization

- **Functionalization** refers to the process of dividing the total costs into three components:
  - Generation
  - Transmission
  - Distribution
- Functionalization is an important step as customers have various electrical service needs:
  - Distribution assets are primarily utilized by residential and commercial customers.
  - Large industrial customers interconnect at the transmission level.
- Proper functionalization ensures that rates are appropriately assigned based on cost causation and characteristics.

Cost of Service
Functionalization FERC Standards

- The process of functionalizing the total costs is straightforward as it typically follows the assignment according to the accounting treatment as set forth in the Uniform System of Accounts (USOA) from the Federal Energy Regulatory Commission (FERC).

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

Cost of Service
Functionalization General Categories

Generation

- Fuel, purchased power, and generation assets

Transmission

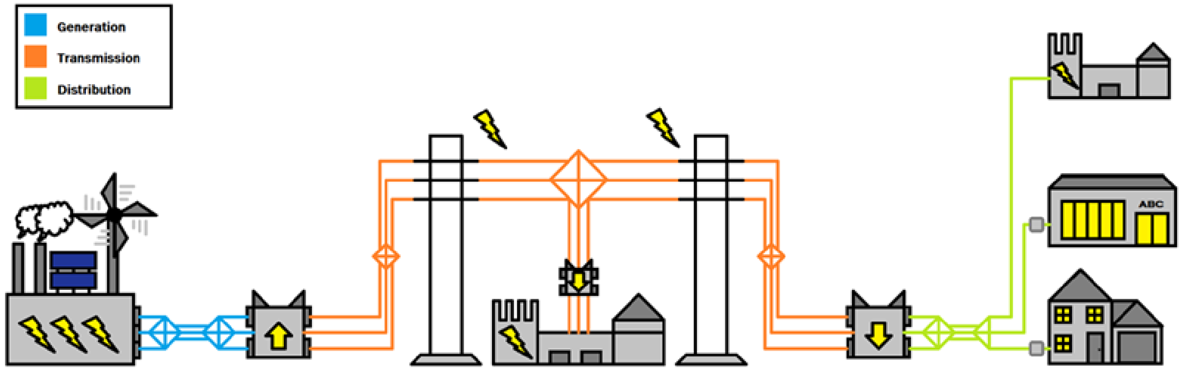
- High-voltage transmission lines (69kV, 161 kV, 345 kV)
- Transmission substations

Distribution

- Distribution substations
- Distribution lines (primary and secondary)
- Overhead and underground services
- Poles
- Meters, service drops, feeders
- Streetlights
- Customer service

General

- General plant and administrative and other general (Needs to be distributed to generation, transmission and distribution)



Cost of Service
Functionalization Transformation

- OPPD is undergoing a transformative period:
  - 1,000 – 1,500 MW of wind and solar
  - 125 MW of battery storage
  - 32+ MW of demand response
  - 600 – 950 MW of combustion turbines
  - 320 MW of added fuel capacity and fuel oil storage
- Changes in our generation mix, growing energy resource needs, and expansion in our residential, commercial, and industrial classes will result in the functionalized total costs evolving over time.
- OPPD will continue to monitor anticipated changes, economic changes, and other factors to maintain gradualism and rate stability.

Cost of Service
Step 2: Classification

- **Classification** identifies the drivers of the costs.
- Costs are generally split into three categories:
  – Demand Costs
    - Costs based on the customer’s maximum demand
    - Measured in kilowatts (kW)
  – Energy Costs
    - Costs based on the customer’s energy needs
    - Measured in kilowatt-hours (kWh)
  – Customer Costs
    - Costs based on the number of customers on the system
    - Measured using customer-months
- Portions of general plant and administration and general expenses are each categorized as energy-related, demand-related, and customer-related.

Cost of Service
Classification Demand-Related Costs

- Demand-related costs are costs that vary based on the size-related needs to serve a customer’s maximum demand.
- All three functionalization categories have size-related needs.
  - Generation costs are the capacity built to meet maximum expected demand and the additional planning reserve margin.
  - Transmission costs are mainly size-related demand costs as transmission facilities transmit bulk power to load centers to meet maximum expected demand.
  - Distribution costs also have size-related demand costs including transformers and conductors to meet maximum expected demand. Customer classes do not have their maximum demands at the same times on the distribution system.

Cost of Service
Classification Energy-Related Costs

- The majority of energy-related costs are generation costs. While some generation assets are built for resiliency and peak demand, generation is also built to serve the energy needs of customers and portions are assigned to energy.
  - The split for generation assets between energy and demand will be discussed in detail below.
- Costs that vary with energy production are categorized as energy-related. Two major cost categories:
  - Fuel is classified entirely as energy-related as energy needs require the consumption on fuel.
  - Purchased power is generally classified as energy-related because power is purchased on the integrated marketplace when OPPD is short energy resources or when market prices are lower than OPPD's variable fuel costs.

Cost of Service

Classification Customer-Related Costs

- The majority of customer-related costs are distribution costs.
- Customer-related costs includes meters, customer billing, and portions of the distribution plant.
- The split between demand-related and customer-related distribution costs is determined by OPPD’s minimum system approach.
- In 2022, OPPD reviewed the classification of its distribution system and enacted the minimum system methodology for its planning system. More information will be discussed in detail below.

Cost of Service
Classification Important Considerations

- Two important classification factor decisions are:
  - The split between demand-related and energy-related generation assets.
  - The split between customer-related and demand-related distribution assets.
- The best strategy for determining the classification approach in an embedded-cost approach is identifying cost causation and system planning.
- OPPD utilizes a load factor approach (a derivative of the "average and excess" approach) for the classification of generation assets.
  - OPPD performed a study considering 14 different demand classification approaches when determining the classification of generation assets.
- The load factor approach uses the system wide load factor to determine the proportion assigned to energy-related costs and the remaining portion is assigned to demand-related costs.
  - Rather than the traditional "excess demand" derivation for the demand-related allocation, the 4CP measure is used (more information provided in allocation section below).
- As previously mentioned, OPPD's generation fleet will change considerably in the future. Additionally, the Inflation Reduction Act of 2022 has significantly impacted the business decisions regarding the owning of utility-scale renewable resources. OPPD will ensure that the classification of generation assets matches the transformation of the generation portfolio.

Cost of Service

Classification Important Considerations (Cont.)

- The classification of the distribution plant is another important consideration (particularly FERC accounts 364–370).
- OPPD has previously used the zero-intercept, but adopted the minimum system approach in 2022 determining it best represented OPPD's system planning.
  - The minimum system approach provides a more intuitive approach to determining the customer-related distribution costs as it assigns a minimum-sized unit cost as the customer-related portion and the remaining costs are assigned as demand-related.
- The minimum system approach was one of many classification, functionalization, and allocation refinements OPPD recently implemented in collaboration with our rate consultant Brattle.
  - These adjustments resulted in greater precision of cost recovery matching cost incurrence for demand, energy, and customer costs.

Cost of Service
Step 3: Allocation

- **Allocation** is the assignment of the classified costs to customer classes based on the relative proportion of their contribution to those costs.
- Allocation is the most critical step of a COSS as it determines the cost allocations for each customer class.
  - It is essential to understand the characteristics of each customer class, such as the number of customers, energy consumed, voltage-level, and their contribution to both coincident peak (CP) and non-coincident peak (NCP) demand.
- Each allocation method represents a set of relative proportions that total to 100% across all customer classes.
- There are multiple allocations used for the various classified costs:
  - Demand-related allocations
  - Energy-related allocations
  - Customer-related allocations

Cost of Service
Allocation Approaches

- Before discussing allocation approaches, it is worth noting certain customer classes will view some allocation approaches more favorably than others.
- OPPD's allocation approach is based on a set of measurable criteria that are universally adopted for determining the appropriateness of an allocation method.
- Some of these criteria include:
  - Measuring the precision of the method compared to the actual planning and operating of facilities.
  - Measuring the accuracy of the method to cost causation.
  - Assessing the ability of the method to recognize specific customer class characteristics, such as energy usage, peak demand, number of customers, etc.
  - Assessing the accuracy of the method to produce consistent results.
  - Reviewing the modernity of the method to reflect best practices across the industry.
- Adhering to these criteria, several methods can be appropriate. OPPD partners with Brattle to provide a balanced approach in selection of allocation methods.
- OPPD does not seek to influence a particular set of results when determining allocation factors.

Cost of Service
Allocation Methods

- Demand-related allocation methods:
  - Coincident peak demand (CP)
    - Also referred to as system peak demand (kW)
    - Depending on the nature of the CP, there are different measures of CP (4CP vs. 12CP)
  - Non-coincident peak demand (NCP)
- Energy-related allocation methods
  - Aggregate energy (kWh)
  - Considered both at point of generation and point of use to account for energy losses
- Customer-related allocation methods
  - Number of customers
  - Weighted customer measures:
    - Relative cost – meters, transformers, service lines, etc.
    - Effort required – customer service, billing, etc.
    - Ratio of service – transformers, connections, streetlights, etc.

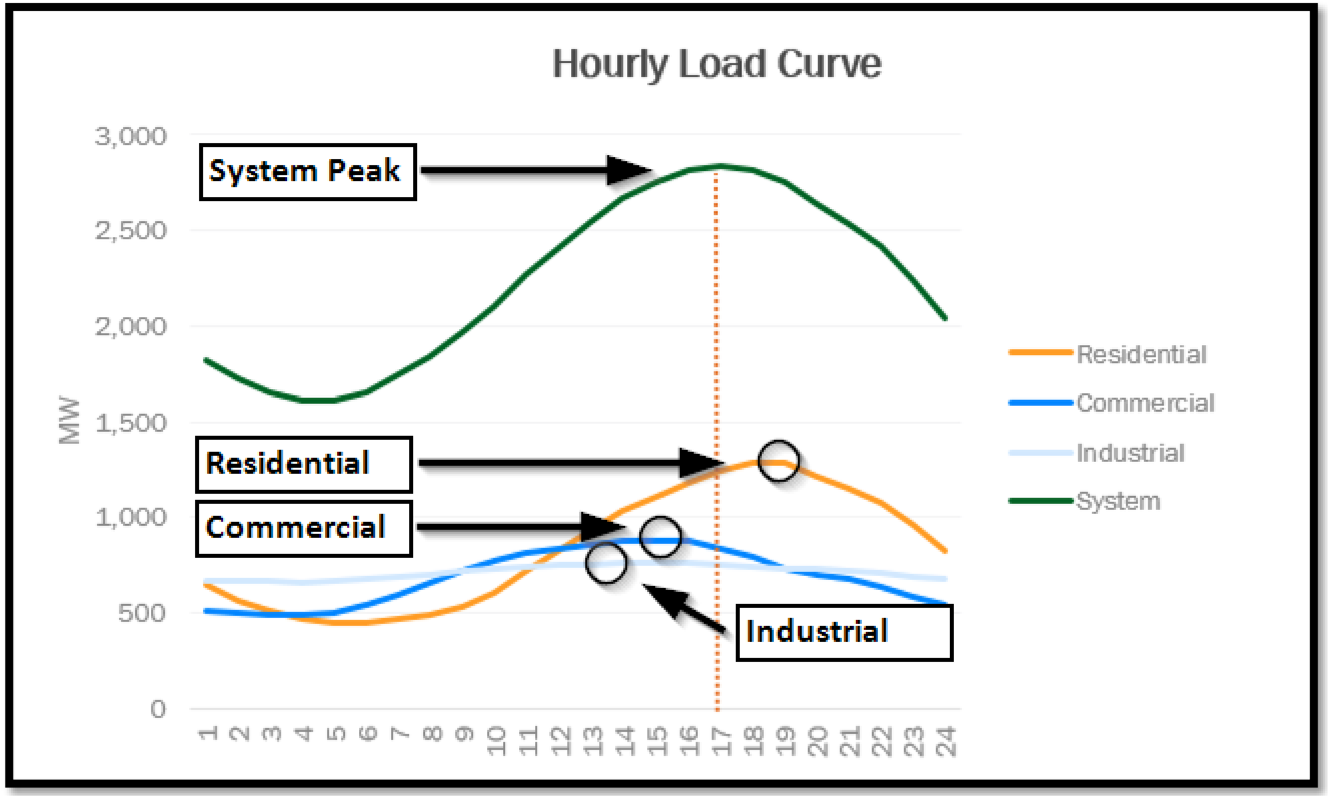
Cost of Service
Demand-Related Allocations

- Coincident Peak (CP) is the demand placed on the system by a customer class at the system peak.
- 4CP measures the CP contribution during the 4 highest months of the year.
  - These are the summer months of June – September for OPPD.
  - This method is used to allocate the demand-related production costs as our capacity and OPPD’s resource adequacy requirement is currently driven by the summer peak. Note: resource adequacy requirements may change as SPP examines system resiliency requirements and may cause a need to reevaluate the 4CP allocation for demand-related production costs.
- 12CP measures the contribution during the system peak hour of each of the 12 months of the year.
  - These are averaged together to provide the 12CP measure.
  - 12CP is widely accepted in allocating transmission costs as it strikes a balance in reflecting the way the system has been planned and is used. This helps to maintain reliability and serve load accordingly.
- Non-coincident peak (NCP) refers to the demand placed on the system by each customer class at the point in time when that class reaches its individual peak demand (regardless of the system peak).
  - This measure is utilized for the allocation of distribution demand-related costs such as substations, which are built to meet the highest instantaneous peak demand regardless of the time of day.

Cost of Service

Load Curve

- The following graph provides an example of a daily load curve cycle and visually illustrates the concept of CP and NCP.
- The **circled points** for each class indicate the **NCP** for each class, while the intersection of each class line with the **dotted line** illustrates their contribution to the **CP** (system peak).
- None of the NCP's align with the CP. However, load variability is distinct between classes. In summer months, generally:
  - Residential peaks in the evening
  - Commercial peaks middle afternoon
  - Industrial peaks early afternoon
    - Industrial is relatively constant throughout the day
- Variability translates to different levels of utilization of system capacity. Load Factor measures utilization efficiency and is important for determining allocation of costs for each class.



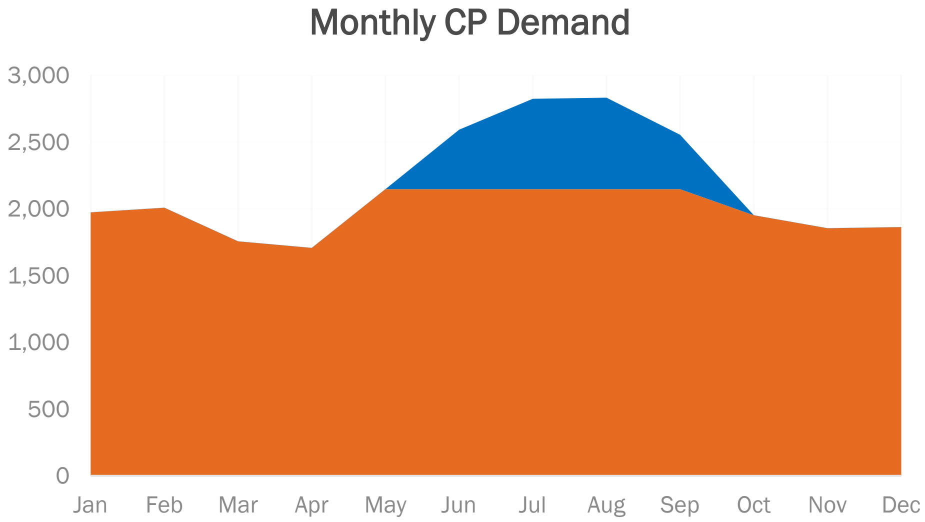
Cost of Service
Load Factor

- Load Factor is a measure that captures variation in load.
- It is calculated as the ratio of average load by peak load:
  - $\text{Load Factor} = \frac{\text{Average Load}}{\text{Peak Load}}, [0,1]$
- Higher load factors indicate higher utilization over all hours of the day and year, which aligns well with baseload generation.
- Baseload generation typically has lower energy costs and higher load factor customers align well with baseload generation (leading to lower rate offerings).
- Differences in load factors can occur within rate classes and can merit different rate offerings based on different levels of utilization of the system.

Cost of Service
Load Factor Impacts on Rates

- Rate 110 (Standard) and Rate 115 (Heat Pump) are both residential rates, but with different load profiles due to Rate 115 requiring an electric heat pump.
  - Rate 115 uses electricity both in heating and cooling of the household, yearly load factors are typically 35% higher than Rate 110 customers.
  - With more load used throughout the year, rates are lower and the average Rate 115 pays approximately 2.2 cents/kWh less than the average Rate 110 customer.
- Electrification of households will allow more efficient recovery of costs and illustrates how load factor is correlated with rates.
- Electrification of transportation can be utilized to increase load factors. Rate offerings will be evaluated to incentive recharging over night (off-peak periods), which would be beneficial to the system. However, if left unaddressed, customer load factors may worsen if charging occurs during on-peak periods.

Cost of Service
Generation Demand-Related Allocations



- OPPD utilizes a derivative of the average and excess approach for classification with the “excess demand” allocation method being 4CP.
- The rationale for utilizing 4CP is illustrated in the monthly peak load graph above.
  - The blue area represents the summer peak demand in excess of the non-summer peak demand (orange area).
  - Therefore, generation capacity and OPPD’s resource adequacy requirement is currently driven by the summer peak.

Cost of Service

Transmission Demand-Related Allocations

- Transmission costs are classified as entirely demand-related using the 12CP allocation.
- The 12CP allocation method is widely accepted as the most appropriate approach for allocation of transmission costs. This is due to the majority of utilities planning their systems to meet their 12 monthly peaks.
  - FERC uses 12CP in allocation of transmission costs.
  - SPP also relies on 12CP for allocation of fees from its members.

Cost of Service
Distribution Demand-Related Allocations

- The 1NCP allocation method is widely accepted and utilized as the distribution demand-related allocator.
  - Transformers, substations and other size-related distribution investments are generally designed for customer's maximum demand needs regardless of the system peak.

Cost of Service
Energy-Related Allocations

- There are several substantial cost categories allocated strictly on energy-related usage including:
  - Fuel
  - Purchased power
  - Portions of generation assets
- Energy is measured in usage at the meter, production at the facility, and adjusted for losses on the system (line, substation, transformer, etc.).
- OPPD captures where customers are located on the system and determines load losses at each interconnection level.
  - Customers interconnected at higher voltage levels have lower energy losses (industrial).
  - Customers interconnected at lower voltage levels have higher energy losses (residential).

Cost of Service
Energy-Related Allocations (Cont.)

- When customers use power is another important factor.
  - Fuel costs are different for different generation types.
  - Purchased power is higher during specific time intervals and seasons.
- Seasonality (summer vs non-summer) for residential and commercial classes provide a means of capturing time of consumption impacts.
- Advanced Metering Infrastructure (AMI) will further enable the ability to provide time-varying rates and better match cost recovery with incurrence.

Cost of Service
Customer-Related Allocations

- Customer-related allocation methods typically involve a weighted-measurement of the number of customers, which controls for variation in customer attributes.
- Customer-related allocation methods include measures such as:
  - Relative cost – meters, transformers, service lines, etc.
  - Effort required – customer service, billing, etc.
  - Ratio of service – transformers, connections, streetlights, etc.
- Customer-related costs are the smallest classified cost category.
- Distribution systems represent the most diverse functional component and require special attention to ensure proper classification and allocation.

Cost of Service

Transmission Level Market Access Rate Allocations

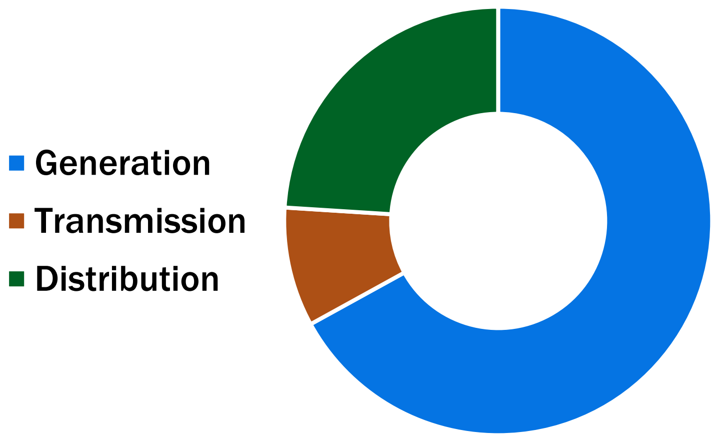
- Large Power – High-Voltage Transmission Level – Market Energy, Rate 261M, reflects a unique customer class and offering.
  - As required, customers are supplied at transmission level voltage 161kv or 345kV and own their own electric substation for the delivery of service.
  - In addition, customer's energy charge is equal to wholesale market prices for energy from the SPP for each hour and these prices are directly passed through to the customer.
- Rate 261M customers have unique allocation factor assignment in the energy components:
  - Each customer receives a direct assignment of the purchased energy costs at the market price.
  - Portions of the generation plant that are classified as energy-related are not allocated to this rate offering as this rate's energy is being directly assigned through its market-access rate.
- The interconnection level is considered in the allocation of functional components.
  - Interconnection at the transmission level avoids much of the distributional investments.
- This unique offering provides a shared risk and investment between the customer and the utility that requires specific allocation considerations.

Cost of Service

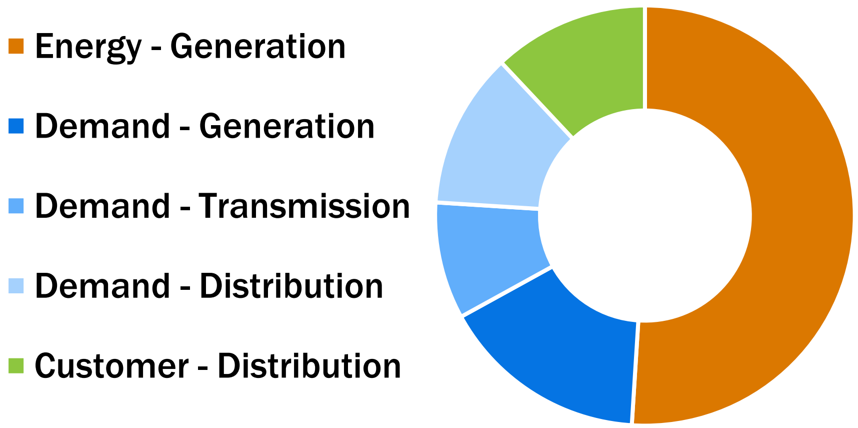
Summary of OPPD Cost of Service Allocations

- The following charts are examples of the proportion of the total costs to serve by functionalization, classification, and main allocation method.

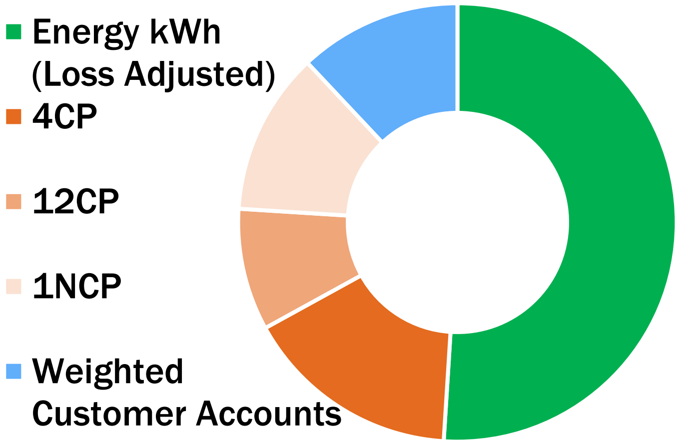
Functionalization



Classification



Allocation Method



IV. Rate Design

Rate Design

Step 4: Rate Design

- The ultimate goal of the COSS is to fairly apportion costs among customer classes based on their proportionate contribution to the costs.
- After determining the total costs for each customer class, cost recovery is aligned with the fundamental rate elements/charges:
  - Demand Costs (Demand Charges)
    - Costs based on the customer's maximum demand
    - Measured in kilowatts (kW)
  - Energy Costs (Energy Charges)
    - Costs based on the customer's cumulative energy needs
    - Measured in kilowatt-hours (kWh)
  - Customer Costs (Service Charges)
    - Costs based on the number of customers on the system
    - Measured using customer-months

Rate Design
Demand Charges

- Demand charges are determined through dividing the demand-related costs by the billing demand (measured in kW).
- Demand charges include the size-related capacity costs of generation, transmission, and distribution.
  - Demand charges must be consistent with the collection method of demand meter data to ensure over/under collection does not occur.
- Demand charges seek to provide price signals to customers regarding instantaneous use costs and serve to more effectively recover demand-related costs based on peak contributions.
- When a class does not have demand metering technology, demand-related costs must be recovered either through:
  - The energy charge or
  - The service charge
- This is discussed below regarding 2-Part Rates vs. 3-Part Rates.

Rate Design
Energy Charges

- Energy charges reflect recovery of energy costs.
- Energy charges can take the form of both **Base Rates** and **Riders.**
  - **Base Rates** are charges set within the service regulations and approved by the Board.
  - **Riders** (sometimes referred to as “trackers”) are additional charges, not included in the base rates, that are designed to recover specific costs that the rider is “tracking,”
    - **Rider 461** - OPPD utilizes a Fuel and Purchased Power Adjustment Rider (FPPA) that recovers fluctuations in net power costs (fuel, purchased power, and off-system sales) outside of OPPD’s control. This rider ensures the base rates remain stable during volatility in the integrated marketplace while also providing an effective price signal to customers.
  - Energy charges can be structured in several different ways:
    - Seasonally – based on the time of year
    - Temporally – based on the time of day or week (AMI-enabled)
    - Volumetrically – based on the volume consumed (e.g. declining-block structures)

Rate Design
Service Charges

- Service charges are used to recover the costs of being a customer.
- Service charges are uniform for all customers taking service on a rate and do not vary based on size-related demand or energy needs.
  - Includes costs such as billing, customer service, meters, etc.
- Service charges are calculated as follows:
  - $\text{Service Charge} = \dfrac{\text{Customer Costs Allocated to Customer Class}}{\text{Number of Customers in Class} \times 12\ \text{Billing Months}}$

Rate Design

2-Part Rates vs 3-Part Rates

- OPPD's residential and small commercial classes lack the supporting infrastructure for demand charges. Therefore, demand-related costs are recovered through service charges and energy charges.
  - Rate offerings with only service charge and energy charges are referred to as **2-Part Rates.**
  - Rate offerings with an additional demand charge component are referred to as **3-Part Rates.**
- For these classes, the energy charge must recover not only energy costs but also generation, transmission, and distribution costs. Increasing diversity of customer needs has made it challenging to effectively recover fixed costs in the absence of time-of-use volumetric energy charges.
  - Customer class divergence includes:
    - Various forms of energy efficiency
    - Electrification of heating
    - Electrification of transportation
    - Customer-owned generation
- OPPD's 2-Part rate structures recovers portions of distribution demand-related costs and the customer-related costs within the service charge while demand-related generation, transmission, and part of distribution costs along with energy costs are recovered through the energy charges.
- OPPD's transition towards more effective price signaling will take a balanced approach over time.
  - In the interim, as we transition to AMI technology, OPPD will seek to align legacy rates with future price signals.
  - This will allow for stability and behavioral shifts in energy consumption that will mitigate transitional challenges.

Rate Design
Generally-Accepted Rate Principles

- There are some generally-accepted rate principles utilized within the electric industry, which include:
  - Customer bill stability
  - Simplicity, understandability, and transparency of rates
  - Rates that support healthy utility operations
  - Rates that promote efficient use and investments
  - Fairness in allocation among classes
- These principles must be properly understood to remain effective in the shifting landscape of energy, which includes:
  - Ongoing technological advancements
  - Growth in distributed energy resources (DER)

Rate Design
Transition Toward Effective Price Signals

- Utility planning has become increasingly sophisticated, and the ability to capture allocators based on more granular load and equipment data has enabled greater precision when determining class-level costs to serve.
- It is also important to adhere to the Efficient-Use Principle, which is defined as providing customers with effective price signals and information to manage their energy costs.
  - Appropriate changes in energy usage will result in a reduction in the costs allocated to them. For example, in the future with AMI-enabled technology, customer interactions will increase in app-based communications, which provide real-time cost savings estimates to encourage more efficient consumption.
- While high-load factor customers have historically matched baseline generation, as the industry moves increasingly towards intermittent renewable generation, customers with flexible demand will be key to the minimization of costs and therefore benefit from incentives and rate offerings.

Rate Design
Transition Toward Effective Price Signals (Cont.)

- AMI technology will be initiated over the next several years and will help OPPD to build more advanced and dynamic rate structures.
- Enabled by this technology, customers will have greater understanding of the drivers of their bill and better ability to respond to price-signals.
  - OPPD will be able to utilize data from AMI-metering to better serve our customers by coordination of customer profiles and usage data allowing for strategic engagement that address customer’s needs and preferences.

Rate Design
Conclusion

- Rate design aligns cost recovery with the fundamental rate element – demand charges, energy charges, and service charges.
- Rate principles provide the guiding vision and long-term strategy to provide customers with greater flexibility, choice, transparency, gradualism, affordability, and fairness when determining rate offerings.
- The utility industry is experiencing rapid developments. Rate structures will need to be able to evolve to be more adaptable to the increasingly dynamic environment and leverage technology that will become available to better serve our diverse customer needs.
- OPPD will continue its partnership with both external entities and our customer-owners to provide affordable, reliable, and environmentally sensitive energy services to our customers.

V. Appendix

Appendix

2022 General Rate Action Results

- The following slides present the Total Cost Determination, Revenue Requirement, by functionalization, classification, and allocation for the 2022 General Rate Action Resolution No. 6481.
- It should be noted that some COSS modifications mentioned in this report occurred after the 2022 General Rate Action and will be employed during the next General Rate Action (like the minimum system approach).
- In alignment with a General Rate Action and the accompanying Board Resolutions, this appendix will be updated with COSS model results the quarter after Board approval.

Appendix
Functionalization of Revenue Requirement

FUNCTIONALIZATION OF REVENUE REQUIREMENT ($1,000)	FUNCTIONALIZED AMOUNTS		
	GENERATION	TRANSMISSION	DISTRIBUTION
Item			
OPERATION & MAINTENANCE EXPENSE			
PRODUCTION EXPENSES	208,497	-	-
PURCHASED POWER AND OTHER PRODUCTION EXPENSES	233,507	-	-
TRANSMISSION EXPENSES	-	56,427	-
DISTRIBUTION EXPENSES	-	-	71,199
CUSTOMER ACCOUNT & A&G EXPENSES	63,715	17,263	102,851
SUBTOTAL OPERATION EXPENSES	505,719	73,690	174,050
DEPRECIATION AND TAXES			
DEPRECIATION EXPENSE	57,987	17,758	68,367
PILOT	25,155	3,275	9,334
SUBTOTAL DEPRECIATION AND TAXES	83,142	21,033	77,701
DECOMMISSIONING & DEBT SERVICE			
DECOMMISSIONING AND AMORTIZATION	145,438	-	-
INTEREST EXPENSE	35,934	13,461	30,817
RETURN REQUIREMENT TO MEET DEBT SERVICE	20,386	7,637	17,483
SUBTOTAL DECOMMISSIONING & DEBT SERVICE	201,758	21,098	48,299
OTHER INCOME & OPERATING REVENUES			
OTHER INCOME AND EXPENSES	(667)	(278)	(16,913)
OTHER OPERATING REVENUES	(69,258)	(21,711)	(15,720)
SUBTOTAL OTHER INCOME & OPERATING REVENUES	(69,926)	(21,989)	(32,633)
TOTAL REVENUE REQUIREMENT	**720,693**	**93,831**	**267,417**

Appendix
Classification of Revenue Requirement

CLASSIFICATION OF REVENUE REQUIREMENT ($1,000)	CLASSIFIED AMOUNTS						
	GENERATION		TRANSMISSION	DISTRIBUTION			
	DEMAND	ENERGY	DEMAND	DEMAND	DEMAND-PRIMARY	DEMAND-SECONDARY	CUSTOMER
Item							
OPERATION & MAINTENANCE EXPENSE							
PRODUCTION EXPENSES	39,633	168,864	-	-	-	-	-
PURCHASED POWER AND OTHER PRODUCTION EXPENSES	16,953	216,553	-	-	-	-	-
TRANSMISSION EXPENSES	-	-	56,427	-	-	-	-
DISTRIBUTION EXPENSES	-	-	-	15,660	26,140	4,625	24,774
CUSTOMER ACCOUNT & A&G EXPENSES	28,182	35,533	17,263	22,369	119	18	80,345
SUBTOTAL OPERATION EXPENSES	84,769	420,950	73,690	38,029	26,258	4,644	105,119
DEPRECIATION AND TAXES							
DEPRECIATION EXPENSE	25,648	32,339	17,758	19,983	17,902	2,769	27,713
PILOT	7,547	17,609	3,275	4,667	-	-	4,667
SUBTOTAL DEPRECIATION AND TAXES	33,195	49,947	21,033	24,650	17,902	2,769	32,380
DECOMMISSIONING & DEBT SERVICE	-	-	-	-	-	-	-
DECOMMISSIONING AND AMORTIZATION	57,766	87,672	-	-	-	-	-
INTEREST EXPENSE	15,894	20,040	13,461	8,672	9,095	1,407	11,643
RETURN REQUIREMENT TO MEET DEBT SERVICE	9,017	11,369	7,637	4,920	5,160	798	6,605
SUBTOTAL DECOMMISSIONING & DEBT SERVICE	82,677	119,081	21,098	13,591	14,255	2,205	18,248
OTHER INCOME & OPERATING REVENUES							
OTHER INCOME AND EXPENSES	(295)	(372)	(278)	(154)	(6,341)	(1,381)	(9,037)
OTHER OPERATING REVENUES	(30,634)	(38,625)	(21,711)	(1,863)	(1,954)	(302)	(11,601)
SUBTOTAL OTHER INCOME & OPERATING REVENUES	(30,929)	(38,997)	(21,989)	(2,017)	(8,294)	(1,683)	(20,638)
TOTAL REVENUE REQUIREMENT	169,711	550,982	93,831	74,254	50,120	7,935	135,109

Appendix
Allocation of Revenue Requirement

ALLOCATION OF REVENUE REQUIREMENT ($1,000)	ALLOCATION AMOUNTS		
	RESIDENTIAL	SMALL GENERAL SERVICE AND MUNICIPAL	LARGE GENERAL SERVICE
Item			
OPERATION & MAINTENANCE EXPENSE			
PRODUCTION EXPENSES	74,647	71,665	62,185
PURCHASED POWER AND OTHER PRODUCTION EXPENSES	70,216	70,677	92,614
TRANSMISSION EXPENSES	21,910	18,032	16,485
DISTRIBUTION EXPENSES	39,641	21,815	9,743
CUSTOMER ACCOUNT & A&G EXPENSES	108,444	46,800	28,585
SUBTOTAL OPERATION EXPENSES	314,857	228,990	209,612
DEPRECIATION AND TAXES			
DEPRECIATION EXPENSE	64,789	48,416	30,905
PILOT	16,072	11,677	10,015
SUBTOTAL DEPRECIATION AND TAXES	80,861	60,094	40,921
DECOMMISSIONING & DEBT SERVICE			
DECOMMISSIONING AND AMORTIZATION	51,984	45,933	47,521
INTEREST EXPENSE	34,449	26,369	19,393
RETURN REQUIREMENT TO MEET DEBT SERVICE	19,543	14,960	11,002
SUBTOTAL DECOMMISSIONING & DEBT SERVICE	105,976	87,262	77,916
OTHER INCOME & OPERATING REVENUES			
OTHER INCOME AND EXPENSES	(12,975)	(3,999)	(884)
OTHER OPERATING REVENUES	(45,457)	(33,394)	(27,839)
SUBTOTAL OTHER INCOME & OPERATING REVENUES	(58,432)	(37,393)	(28,722)
TOTAL REVENUE REQUIREMENT	**443,263**	**338,953**	**299,726**