Omaha Public Power District
BOARD OF DIRECTORS

Agenda

OPPD Board of Directors – All Committees Meeting
Tuesday, November 17, 2026
CLOSED SESSION 8:00 A.M. - PUBLIC SESSION 10:00 A.M.

Conducted in person at BCBS, Aksarben Conference Room and virtually via WebEx audio/video conference. Public may attend remotely by going to www.oppd.com/CommitteeAgenda to access the WebEx meeting link or the public may attend in person at BCBS, 1919 Aksarben Dr –Wahoo Room Omaha, NE, which will be set up as a physical location to view the WebEx.

	TOPIC	TYPE	PRESENTER	TIME*	
1.	**Chair Opening Statement**		Core	**8:00**	**A.M.**
2.	**Closed Session**			**8:05**	**A.M.**
	CEO Succession and Interim CEO Appointment	Discussion	Core	105	min
	Break – Open WebEx to Allow Public to Join			**9:50**	**A.M.**
3.	**Chair Opening Statement**		Core	**10:00**	**A.M.**
4.	**Committee Briefings**			**10:05**	**A.M.**
	Governance Pre-Committee (11/10/26)	Reporting	Spurgeon	5	min
	SM&NO Pre-Committee (11/09/26)	Reporting	Williams	5	min
	Customer and Public Engagement Pre-Committee (11/09/26)	Reporting	Howard	5	min
	Finance Pre-Committee (11/06/26)	Reporting	Moody	5	min
5.	**Financial Stewardship**			**10:25**	**A.M.**
	2027 Preliminary Corporate Operating Plan	Reporting	Underwood	90	min
	Lunch Break			**11:55**	**A.M.**
	Financial Stewardship (Cont'd)			**12:25**	**P.M.**
	Third Quarter Financial Report	Reporting	Underwood	10	min
	Third Quarter Retirement Fund Report	Reporting	Underwood	5	min
	Retirement Plan Investment Policy Update	Action	Underwood	15	min
6.	**Infrastructure Investment**			**12:55**	**P.M.**
	Cass to Nebraska City Transmission Project - Route Announcement	Reporting	Via	10	min
	Acquisition of Land Rights for Utility Operations Infrastructure Projects - Cass to Nebraska City Transmission Project	Action	Fischer	5	min
	Bellevue Reliability Project: Olde Towne Transmission - Route Announcement	Reporting	Via	10	
	Acquisition of Land Rights for Utility Operations Infrastructure Projects - Bellevue Reliability Project: Olde Towne Transmission	Action	Fischer	5	min
	New Generation and Transmission Update	Reporting	Via	20	min
	Hastings/Grand Island Utilities Inter-local Agreement	Action	Via	5	min
	RFP 6263 - Nebraska City 1 House Service Transformer	Action	Via	5	min
7.	**Oversight and Monitoring**			**1:55**	**P.M.**
	Nuclear Oversight Committee Quarterly Report	Reporting	Via	10	min
	Severance Agreement in Excess of $50,000	Reporting	Wheeler	5	min

	SD-11: Economic Development Monitoring Report	Action	McAreavey	15	min
8.	**Governance and Board Matters**			**2:25**	**P.M.**
	Appointment of Interim CEO	Action	Spurgeon	10	min
	Update to 2027 Board Meeting Schedule	Action	Focht	5	min
	Confirmation of Board Meeting Agenda	Action	Core	5	min
9.	**Opportunity for Public Comment on Items of District Business**		Core	**2:45**	**P.M.**
	Break				
10.	**Closed Session**			**3:00**	**P.M.**
	Strategic Risk: Integrated System Plan (ISP)	Discussion	Underwood	90	min
11.	**Adjournment**				

***** All times and duration are estimates. Please use the link below to find board agendas, materials and schedules. Board governance policies and contact information for the Board and Executive Leadership team also can be found at www.oppd.com/BoardMeetings.

Omaha Public Power District

Pre-Committee Agenda

GOVERNANCE PRE-COMMITTEE MEETING
WEBEX VIDEOCONFERENCE
November 10, 2026, 8:00 – 10:00 A.M.

1. Safety Briefing (Wheeler – 1 min)

2. Prior Month Pre-Committee Action Items (Lane – 1 min)
    a. Objective: Review and confirm prior pre-committee action items have been completed.

3. CEO Succession & Interim Appointment Process (Spurgeon – 60 min)
    a. Objective: Discuss next steps regarding CEO replacement process.

4. Development of Slate for January 2027 Election of Board Officers (Spurgeon – 30 min)
    a. Objective: Begin process for developing the slate of Board officer candidates for the January 2027 Board elections, in accordance with *GP-5: Election of Board Officers*.

5. Ethics Reporting (Wheeler – 5 min)
    a. Objective: Confirm with the Governance Committee Chair whether any ethics-related allegations have been reported or investigated.

6. Severance Agreement in Excess of $50,000 (Wheeler – 5 min)
    a. Objective: Inform Board of an employee severance agreement in excess of $50,000.

7. 2027 Board Meeting Schedule Update (Focht – 5 min)
    a. Objective: Discuss changes to the start time of Board Meetings in 2027.

8. Board Workplan (Focht – 5 min)
    a. Objective: Review, discuss, prioritize and confirm items on the Board Work Plan.

9. Governance Committee Planning Calendar (Focht – 1 min)
    a. Objective: Review and confirm items on the Planning Calendar.

10. Summary of Meeting (Lane - 1 min)
    a. Objective: Summarize action items from committee discussion.

GOVERNANCE COMMITTEE	TYPE	PRESENTER	TIME	MINS
Governance Pre-Committee (11/10/2026)	Reporting	Spurgeon	5	min
Update to 2027 Board Meeting Schedule	Action	Focht	5	min
Severance Agreement in Excess of $50,000	Reporting	Wheeler	5	min
CEO Succession and Interim CEO Appointment (CLOSED SESSION)	Discussion	Core	45	min
Appointment of Interim CEO	Action	Core	5	min

Omaha Public Power District

Pre-Committee Agenda

SYSTEM MANAGEMENT & NUCLEAR OVERSIGHT
PRE-COMMITTEE MEETING
WEBEX VIDEOCONFERENCE
November 9, 2026, 8:00 – 9:30 A.M.

1. Safety Briefing (Pohl – 1 min)
    a. Objective: Promote awareness of current safety focus.

2. Prior Month Pre-Committee Action Items (Pohl – 1 min)
    a. Objective: Review and confirm prior SMNO pre-committee action items have been completed.

3. **Integrated System Plan Update (Underwood – 20 min)
    a. Objective: Provide an update on various aspects of the Integrated System Plan.

4. **2027 Preliminary Corporate Operating Plan (Underwood – 40 min)
    a. Objective: Provide a preview of the 2027 Preliminary Corporate Operating Plan that will be presented at the All-Committee meeting.

5. **Transmission Project Updates (Via – 10 min)
    a. Objective: Provide updates on the Cass to Nebraska City Transmission Project and the Old Towne (Bellevue) Transmission Project, including request for board approval for acquisition of land rights.

6. **Interlocal Agreements for Transmission Operator (TOP) Services with Hastings Utilities and Grand Island Utilities (Via – 5 min)
    a. Objective: Discuss request for board approval of interlocal agreement.

7. Board Work Plan – Systems Committee Items (Focht – 1 min)
    a. Objective: Review the current board work plan.

8. Summary of Meeting (Pohl – 1 min)
    a. Objective: Summary of committee action items.

9. SMNO Pre-Committee Open Discussion (Williams – 5 min)
    a. Objective: Opportunity for the SMNO Pre-Committee Board members and ELT to discuss any topics brought forth.

** Indicates topic that will be included on all committee meeting agenda.

Omaha Public Power District

Pre-Committee Agenda

CUSTOMER AND PUBLIC ENGAGEMENT PRE-COMMITTEE MEETING
TEAMS VIDEOCONFERENCE
November 9, 4:00 – 5:15 P.M.

1) Safety Briefing (Jameson – 2 min.)
   a) Objective: Promote awareness of current safety focus.

2) Prior Month Pre-Committee Action Items (Jameson – 1 min.)
   a) Objective: Review and confirm prior pre-committee action items have been completed.

3) *SD-11 Economic Development Monitoring Report (McAreavey – 20 min.)
   a) Objective: Provide an update on OPPD's economic development efforts under SD-11 and confirm continued policy compliance.

4) Advanced Metering Infrastructure (AMI) Update (McAreavey – 20 min.)
   a) Objective: Provide an update on rollout progress, outline recent access challenges and how we've resolved them, and share customer reactions and customer experience wins.

5) External Messaging Update (McAreavey – 20 min.)
   a) Objective: Align on core external messages and clarify how we're addressing key concerns such as load growth, cost allocation, and rate pressure.

6) Board Work Plan – Public and Customer Engagement Committee Items (Focht – 1 min.)
   a) Objective: Committee members review, discuss, prioritize, and confirm items on the Board Work Plan.

7) Summary of Meeting (Jameson – 1 min.)
   a) Objective: Summarize action items and identify topics for All-Committee review.

8) Customer & Public Engagement Pre-Committee: Open Discussion (Howard – 10 min.)
   a) Objective: Provide an opportunity for the Customer & Public Engagement Pre-Committee Board members and ELT to raise and discuss any relevant topics.

*Topics that will go to All-Committee meeting through CUSTOMER AND PUBLIC ENGAGEMENT.
**Topics that will go to Closed Session during All-Committee meeting.

Omaha Public Power District

Pre-Committee Agenda

FINANCE PRE-COMMITTEE MEETING
VIDEOCONFERENCE
November 6, 2026 8:00 – 10:00 AM

1) Safety Briefing (de la Torre - 1 min)
   a) Promote awareness of current safety focus.

2) Prior Month Pre-Committee Action Items (de la Torre – 1 min)
   a) Objective: Review and confirm prior pre-committee action items have been completed.

3) Third Quarter Retirement Fund Report (Underwood- 2 min)*
   a) Objective: Provide awareness of reporting item going to the All-Committee meeting.

4) Retirement Plan Investment Policy Update (Underwood- 17 min)*
   a) Objective: Present proposed changes to the Retirement Plan Investment Policy Statement in preparation for upcoming board action.

5) Third Quarter Financial Report (Underwood- 10 min)*
   a) Objective: Briefly present and answer questions on the report of OPPD's financial results for the three quarters ended September 30, 2026.

6) 2027 Preliminary Corporate Operating Plan (Underwood- 70 min)*
   a) Objective: Preview of the 2027 Preliminary Corporate Operating Plan that will be presented at the All-Committee meeting.

7) Board Work Plan – Finance Committee Items (Focht- 5 min)
   a) Objective: Committee members to review and confirm items on the Board Work Plan.

8) Summary of Meeting (de la Torre- 3 min)
   a) Objective: Summarize action items from committee discussion.

9) Finance Pre-Committee Strategic Discussion (Moody- 10 min)
   a) Objective: Open discussion of any timely strategic and finance items.

*Topics that will go to All-Committee meeting through Finance

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Omaha Public Power District
BOARD OF DIRECTORS

Reporting Item

November 17, 2026

ITEM
Preliminary 2027 Corporate Operating Plan and Rate Action

PURPOSE
The Preliminary 2027 Corporate Operating Plan (COP), incorporating elements of the District's budgeted operations, capital expenditures, and fuel needs for the year, has been completed and is ready for discussion with the Board of Directors

FACTS

a. The Preliminary Corporate Operating Plan includes a total average rate impact across all customer classes of 6.7%, comprised of an 8.0% general rate increase and a 1.3% Fuel and Purchased Power Adjustment (FPPA) rate decrease. The FPPA base rate was reset to account for long-term price increases in the supply of power.
   - The current Fuel and Purchased Power Adjustment (FPPA) factor is 0.521 cents per kWh. The FPPA base rate is 1.951 per kWh.
   - The proposed FPPA base rate will change to 2.498 per kWh and the FPPA factor will change to 0.326 cents per kWh.

b. A Cost-of-Service Study was performed to determine the cost of providing electric service to each rate class. The study was used as a baseline to determine the appropriate rate increase for each class.

Customer Class	FPPA Rate	General Rate	Average
Residential	(1.3%)	4.3%	3.0%
Commercial	(2.0%)	7.6%	5.7%
Industrial	(0.7%)	11.7%	11.0%
Lighting	(0.4%)	6.8%	6.4%
Wholesale Towns	(2.4%)	5.4%	3.0%
Average	(1.3%)	8.0%	6.7%

The proposed increases are detailed in Exhibit A (attached).

c. Miscellaneous wording and rate changes to various rate schedules are also proposed. These proposed changes are detailed in Exhibit B (attached).

d. Total energy sales are budgeted to be 20,025 GWh which represents a 6.4% increase.
   - Retail sales are budgeted to be 17,098 GWh which represents a 10.8% increase.
   - Wholesale revenues, excluding Nebraska City Station Unit 2 (NC2) participation sales, are budgeted to be 1,155 GWh which represents a 13.7% decrease.
     - NC2 participation sales are budgeted to be 1,771 GWh, a 14.2% decrease.

e. Total operating revenues are budgeted to be $2,049.7 million, which is an increase of 13.9%.

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- Retail revenues are budgeted to be $1,737.5 million, which is an increase of $204.3 million or 13.3%.
- Wholesale revenues, excluding NC2 participation revenues, are budgeted to be $177.8 million, which is 35.7% higher.
  - NC2 participation revenues are budgeted to be $73.1 million, a 6.3% decrease.

f. Total operations and maintenance expenditures are budgeted to be $1,490.7 million. Total operations and maintenance expenditures are $218.7 million or 17.2% higher.
- Operations and maintenance expenditures (excluding fuel and purchased power) are budgeted to be $724.4 million, which is $79.6 million or 12.3% higher.
- Fuel expenses are budgeted to be $229.7 million which is $19.8 million or 9.4% higher.
- Purchased power expenses are budgeted to be $536.6 million which is $119.3 million or 28.6% higher.

g. Capital expenditures are budgeted at $1,446.0 million compared to $1,190.0 million budgeted for 2026.

The capital expenditure plan provides for expansion and improvements to the production, transmission and distribution systems. Expenditures by classification include both approved and pending capital projects. Actual expenditures by classification will vary based on final project designs, corporate priorities, and pending project approvals.

	$ in millions
Production	842.4
Transmission & Distribution	525.8
General	100.0
Total Direct Capital	1,468.2
Indirect Capital Expenses	67.8
Contributions in Aid of Construction	(90.0)
Total Capital Expenditures	1,446.0

h. Net income for 2027 is budgeted to be $168.1 million compared to $208.0 million budgeted for 2026.

i. The 2027 Corporate Operating Plan total expenditure amount equals $3,380.7 million.

j. Total debt service coverage is anticipated to be 2.0 times for 2027.

RECOMMENDED:

DocuSigned by:
Bradley Underwood
D7040027FE154E8...
Bradley R. Underwood
Vice President and Chief Financial Officer

APPROVED FOR REPORTING TO BOARD:

Signed by:
L. Javier Fernandez
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L. Javier Fernandez
President and Chief Executive Officer

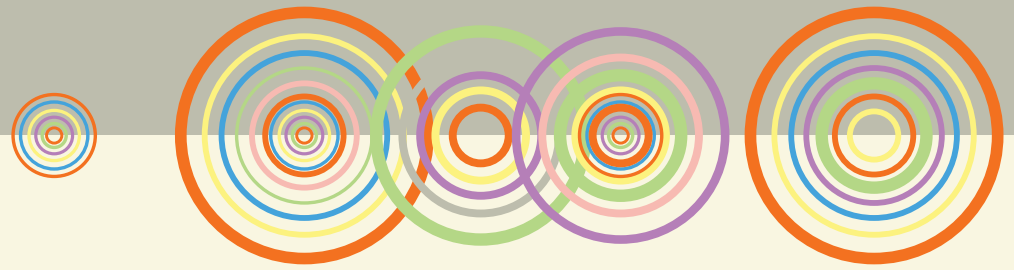
Attachments: 2027 Preliminary Corporate Operating Plan
Letter from The Brattle Group – Financial Review
Letter from The Brattle Group – Rates Review
Exhibit A – Proposed Rate Adjustments

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Exhibit B – Proposed Service Regulations and Schedules Revisions
Red-line of full Service Regulations and Schedules

PRELIMINARY 2027 CORPORATE OPERATING PLAN

11.17.26



Brad R. Underwood
Vice President and Chief Financial Officer

OPPD
Omaha Public Power District

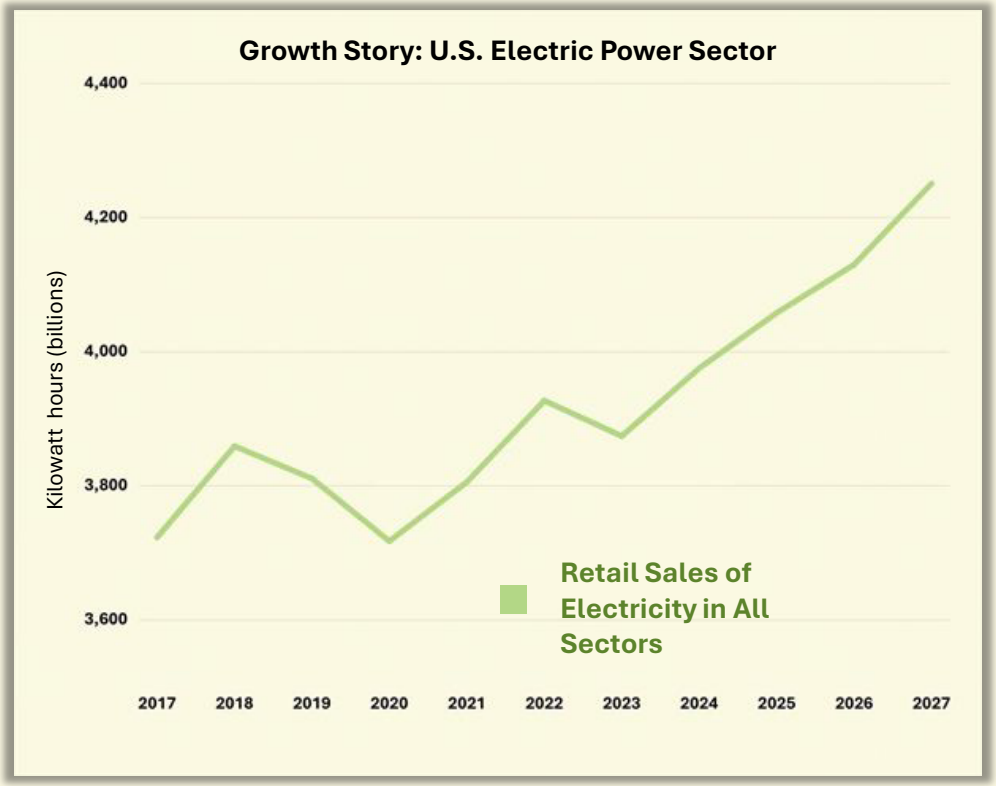
AGENDA

- State of the Industry
- Organizational Performance
- Investments: Reliability and Growth
- 2027 Financial Overview
- 2027 Rate Action
- Customer Outreach

STATE OF THE INDUSTRY

CUSTOMER DEMAND

Retail sales of electricity is growing nationally



SOURCE: U.S. Energy Information Administration

Nebraska is the seventh-fastest growing state when annualized over time.

A sampling of growth rates in other states:

Compound annual growth rates (CAGR) for electric retail sales by state and by total megawatts hours between 2020 and 2024*

- OPPD: 4.81%
- Texas: 3.44%
- Virginia: 3.32%
- Nebraska: 2.46%
- Iowa: 1.64%
- Florida: 1.02%
- Kansas: 0.88%

SOURCE: U.S. Energy Information Administration: Retail sales of electricity by state, all sectors
*Most recent data available

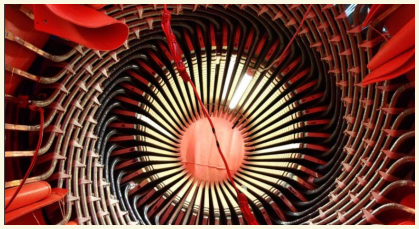
RISING INFLATION

↑104%
COPPER

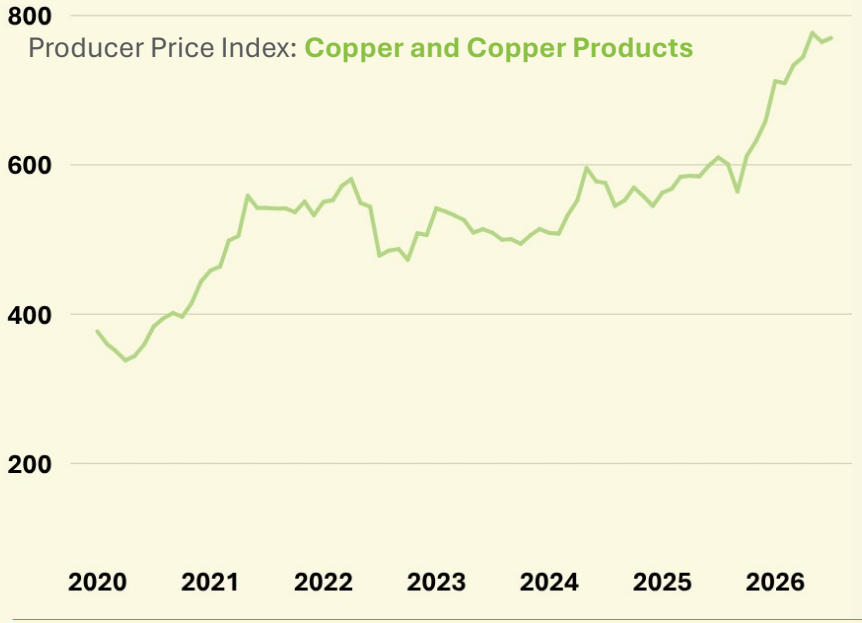
↑ 91%
MACHINERY

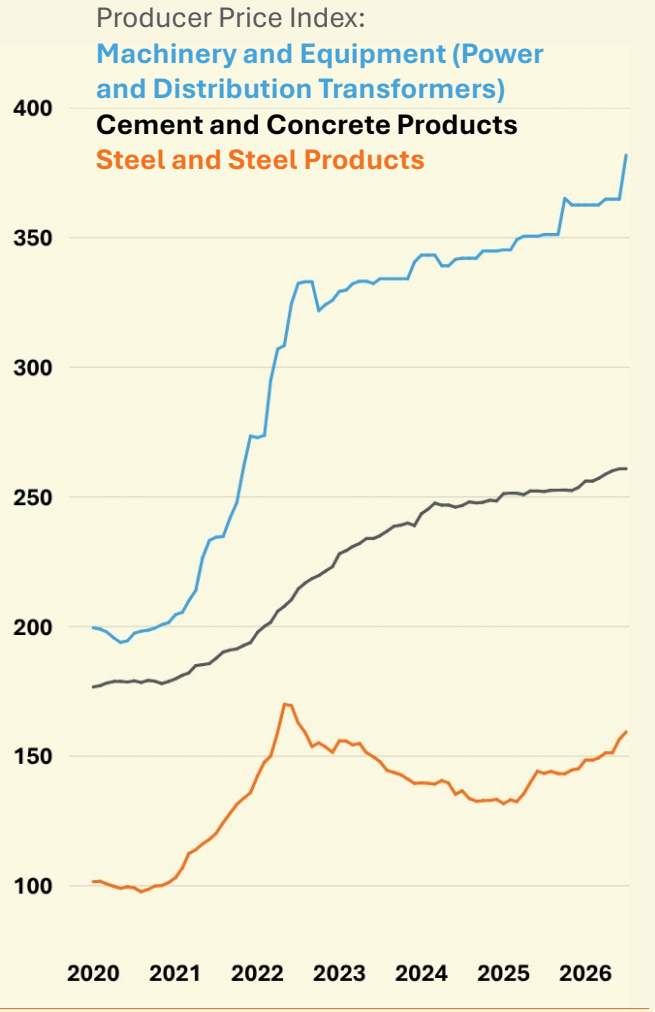
↑ 48%
CEMENT

↑ 57%
STEEL



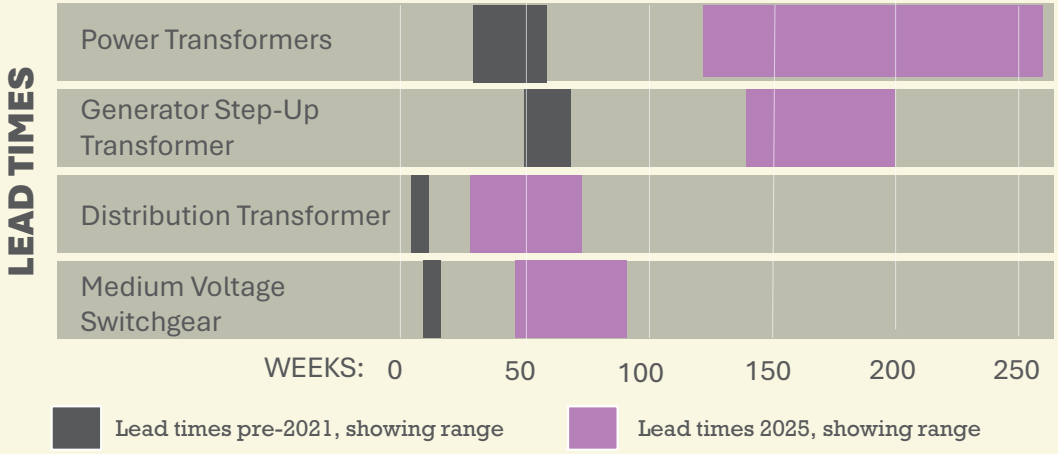






SOURCE: U.S. Bureau of Labor Statistics





SUPPLY CHAIN LEAD TIME EXTENSION

Demand for grid equipment has grown across all categories. Here's the increase in weeks of lead time that OPPD is seeing for substation alone:

- Auto Transformer: ↑140%
- Control buildings: ↑188%
- Connectors: ↑192%
- 69kV breakers: ↑182%

Numbers reflect growth in lead times generally between early 2026 and summer 2026, with the jump in breakers happening over a two-week period.

Transformer lead times shifted between 2025 and 2026.

Source for national lead times: Deloitte

ORGANIZATIONAL PERFORMANCE

STRONG FINANCIAL POSITION

District is improving financial fundamentals through strategic investments

Electric Plant

68%

Up from 2020

Building the value of our physical assets – plants, poles, substation – through strategic investments



Total Assets

73%

Up from 2020



Electric Energy Sales

Driving revenue to support investments in reliability and expansion

41%

Up from 2020

Net Utility Plant

157%

Up from 2020

Improving our competitiveness while maintaining reliability



Net Position (equity)

Strengthening our balance sheet

64%

Up from 2020



We're building.
We're modernizing.
And we're financially stronger because of it.

COMPETITIVE RATES

OPPD Peak Load and Percentage Below Regional & National Average*



New winter peak

- 2,414MW in January 2026
- Up 670MW since 2019, the equivalent of Spokane, Wash.

New summer peak

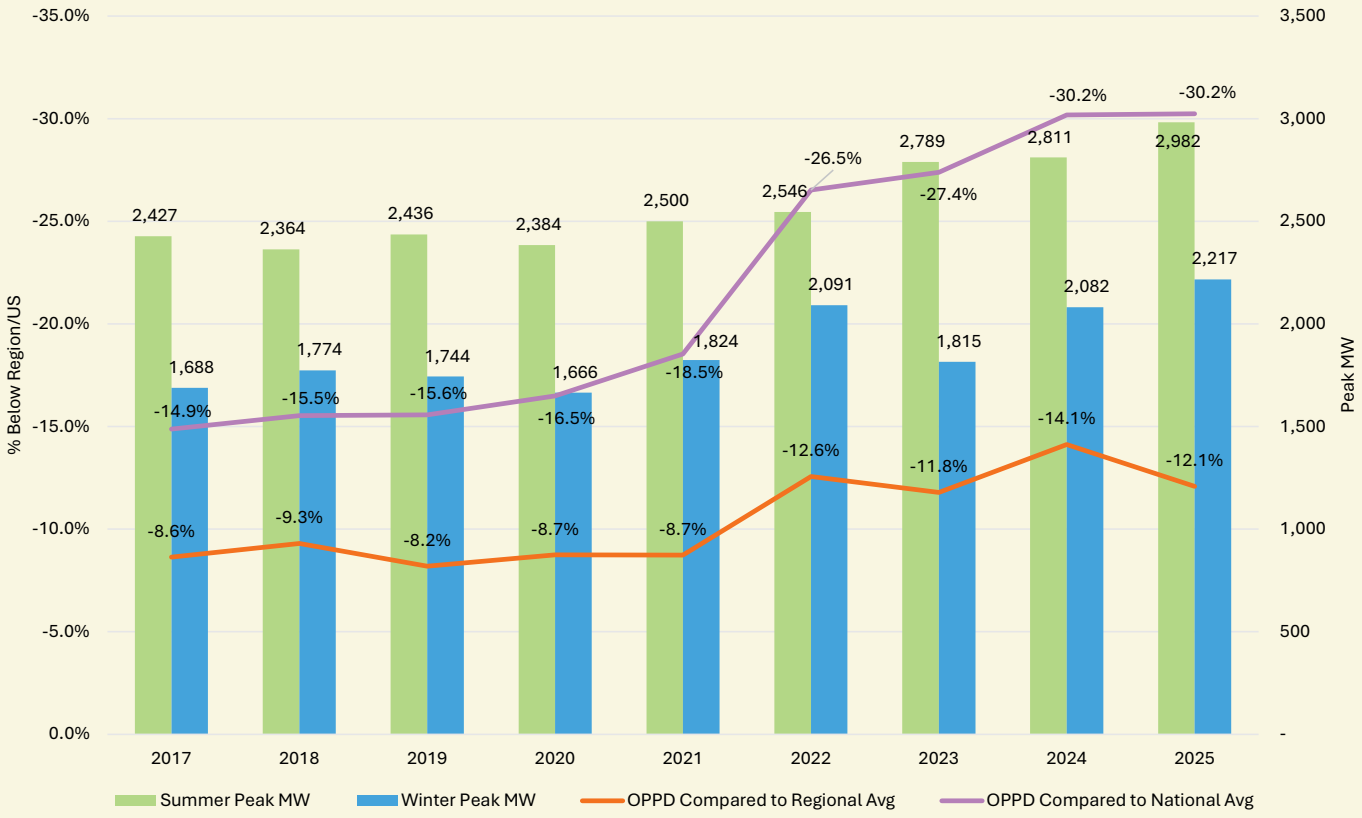
- 3,285MW on July 26, 2026
- Up 849MW, the equivalent of Lincoln, Neb.

BROKE AT LEAST ONE LOAD RECORD IN EVERY YEAR SINCE 2019

*EIA-defined region (West North Central Region) composed of: Iowa, Kansas, Minnesota, Missouri, Nebraska, North Dakota, and South Dakota

COMPETITIVE RATES

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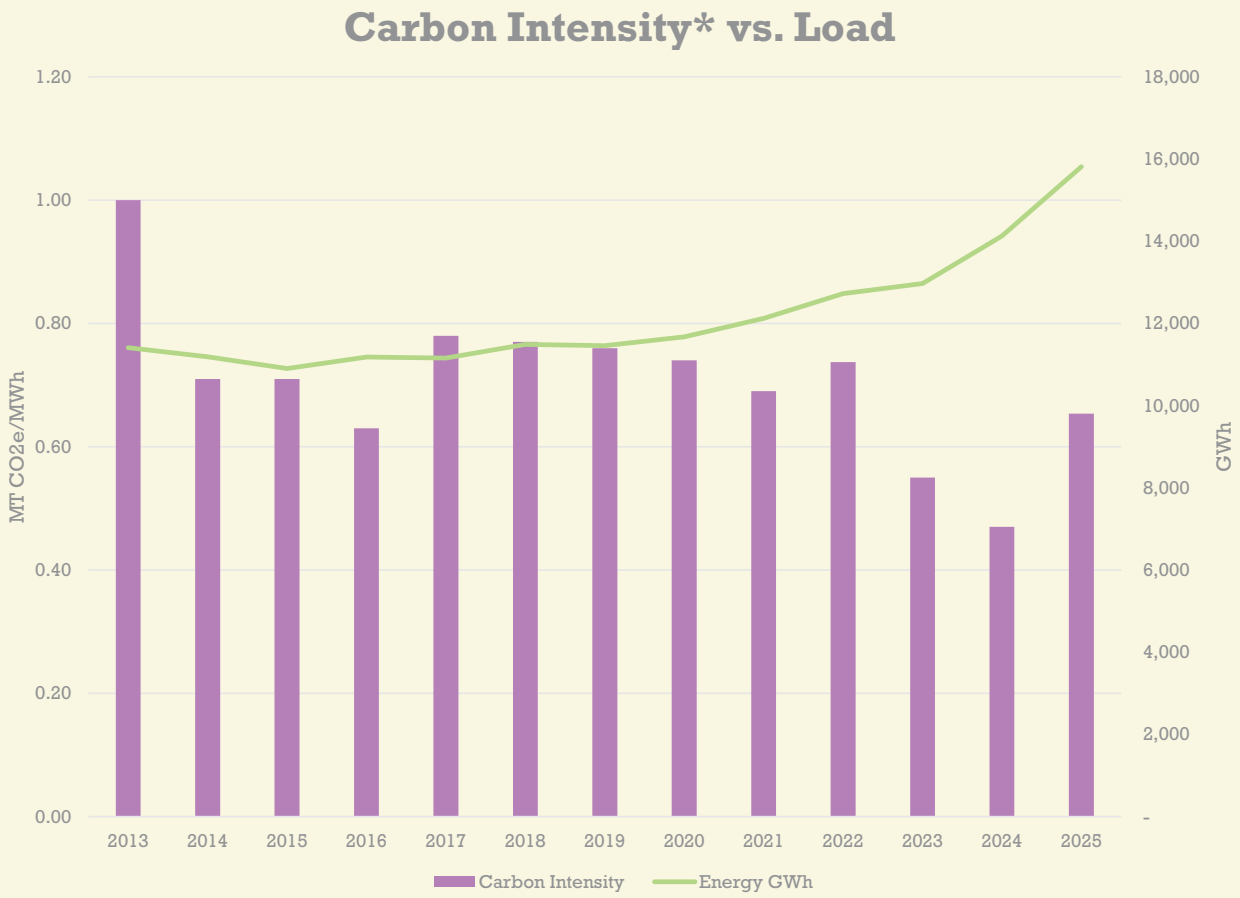
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ENVIRONMENTAL PERFORMANCE

Even as load grows, OPPD is making progress on the path to net zero goal



↑39%

LOAD

↓31.6%

ABSOLUTE EMISSIONS

*OPPD's Carbon Intensity calculation takes into account all GHG emissions emitted from electricity generated or purchased. Contracts that are Capacity Only are not included in these calculations. OPPD began the sale of RECs in 2024 and recommends customers to use USEPA eGRID for emission factors.

INVESTING FOR CUSTOMERS

DECADE OF GROWTH

WE ARE HERE

Joint Transmission Projects: North and South



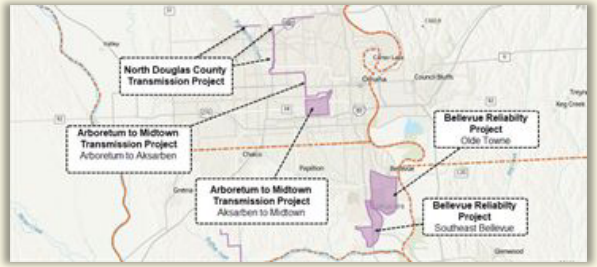
WHAT DO YOU THINK WILL IMPACT OUR ENERGY FUTURE?

Visit OPPDCommunityConnect.com/isp to catch up on the Integrated System Plan process and provide your input.

2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037



Concrete pour at Turtle Creek Station



Active Transmission Projects



TCS Generator



North Douglas County Transmission Project

RELIABLE GROWTH

Expansion and modernization planned over the next decade

400+
miles of new transmission
↑400%*

425,000
Modern meters installed







2
power station expansions

4
New solar, wind and storage agreements

1,651
Megawatts of new or planned renewable energy since 2024

* % increase compared to previous decade

MAJOR PROJECTS

Building infrastructure at a historic size and scale

As part of our expansion, OPPD has...

- Built the **tallest transmission structures** in company history – Platte River crossing.
- Poured the **widest transmission foundation** in the district at 14 feet, requiring continuous pours from 40 concrete trucks
- Managed **six heavy hauls** to support turbine and generator deliveries -- more to come
- Logged more than **965,000 construction work hours** since January by contractors on generation builds.







2027 FINANCIAL OVERVIEW

2027 Budget Assumptions

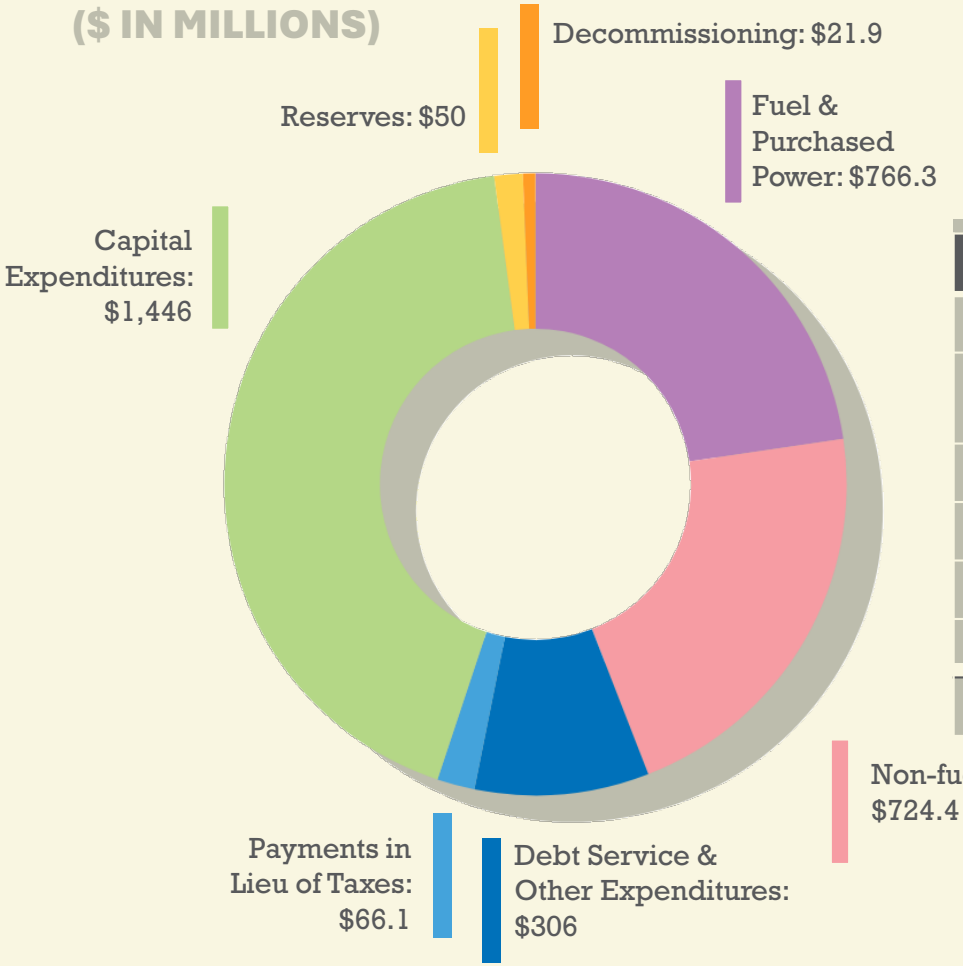


2.0x	230	1.6x	5%	
Debt Service Coverage	**Days of Cash on Hand**	**Fixed Charge Ratio**	**Borrowing Rate**	**Building Reserves**
Ensures OPPD can cover debt obligations and helps maintain favorable borrowing rates	Provides sufficient liquidity to support cash flow needs	Ensures we can meet our fixed financial obligations – including renewable PPAs - using earnings and cash flow	Assumes interest rate levels will rise during 2027	Mitigates rate volatility as we build new generation

EXECUTIVE SUMMARY

($ IN MILLIONS)





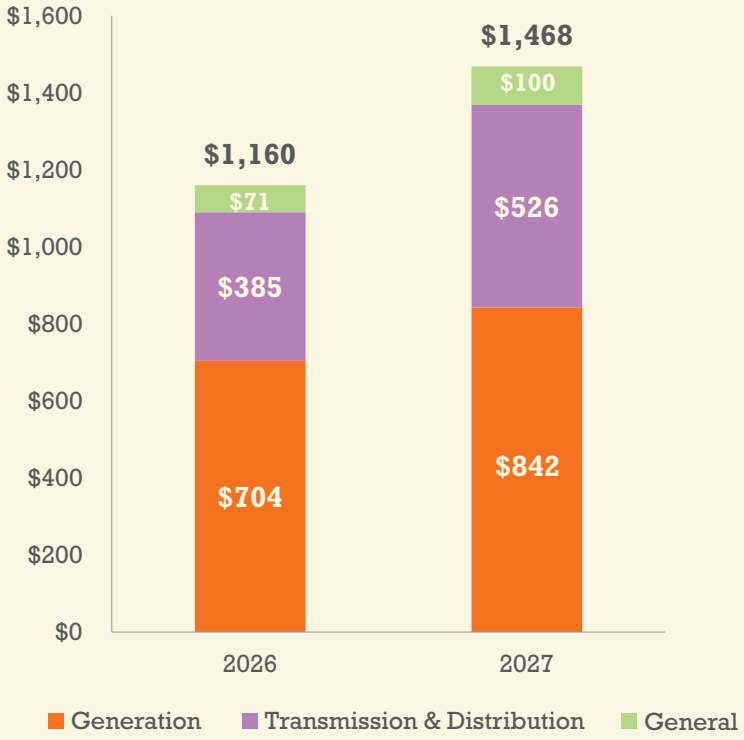
2027 Operating Budget of $3.4B

	2026	2027	Change
Capital Expenditures	$1,190.0M	$1,446.0M	$256.0M
Operations & Maintenance	644.8M	724.4M	79.6M
Fuel & Purchased Power	627.2M	766.3M	139.1M
Debt Service	228.6M	306.0M	77.4M
PILOT	57.1M	66.1M	9.0M
Decom / Other	107.5M	71.9M	(35.6M)
Total	$2,855.2M	$3,380.7M	$525.5M

CAPITAL EXPENDITURES

DIRECT CAPITAL ($ IN MILLIONS)



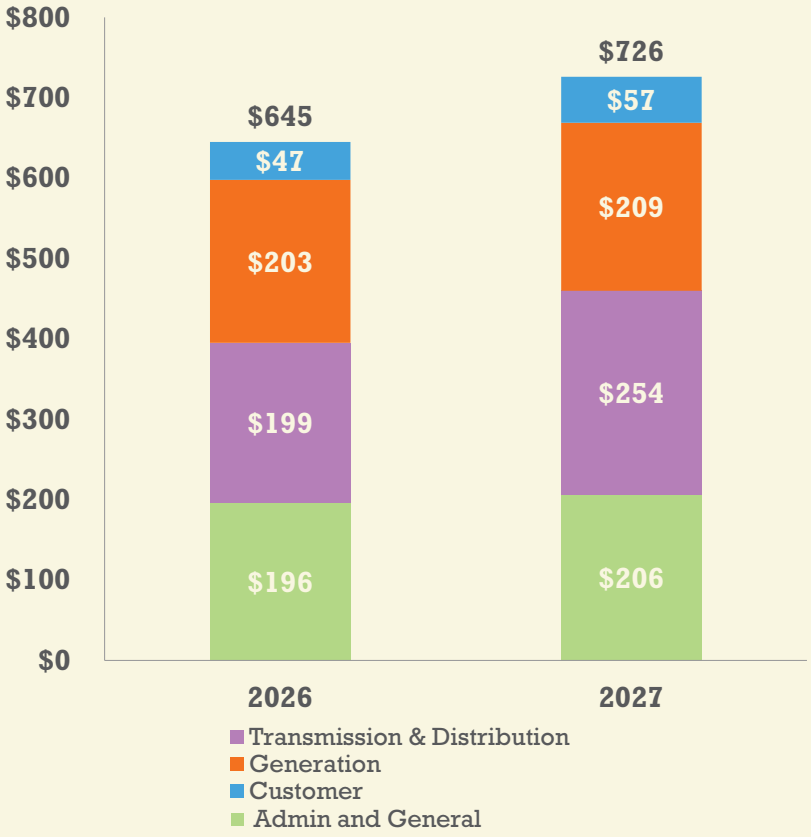


Key growth drivers:

- **Generation:** Up $138 million for construction of four combustion turbines at Turtle Creek and Cass County and reliability investments
- **Transmission & Distribution:** Up $141 million to expand and improve the system in support of new generation, growth and reliability
- **General:** Fleet, facilities and new technology investments drive $29 million in growth
- **Inflation:** Rising costs for material and specialized labor

OPERATIONS & MAINTENANCE

O&M BUDGET* (IN MILLIONS)





Key growth drivers:

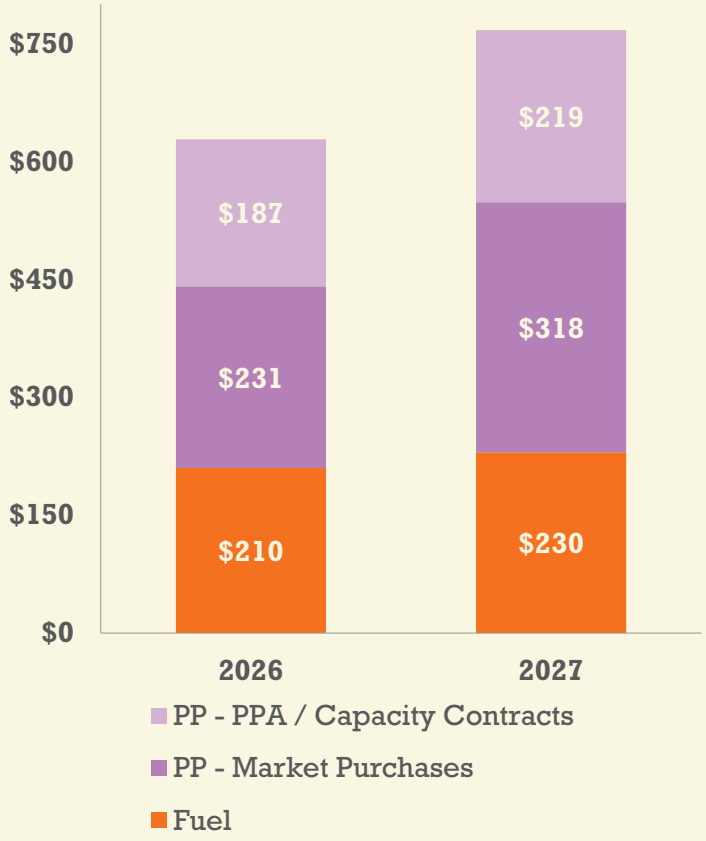
- **Production:** Generation fleet expansion, which requires additional operations, maintenance and head count
- **Transmission & Distribution:** Increased tree trimming $15M (approximately 60% year over year) and SPP fees related to transmission growth
- **Administrative & General (A&G):** Higher employee benefit expenses
- **Customer:** Distributed Capacity Procurement Plan – a part of the North Omaha Station resolution to modernize the local grid

*Excludes Energy Cost & Decommissioning Funding

FUEL AND PURCHASED POWER

($ IN MILLIONS)



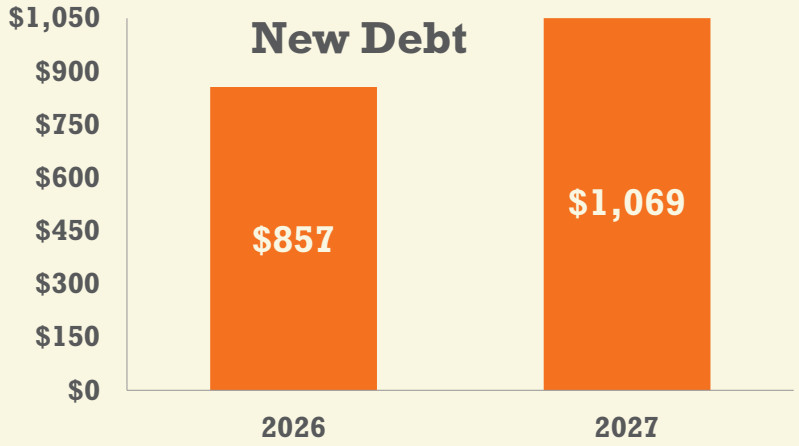


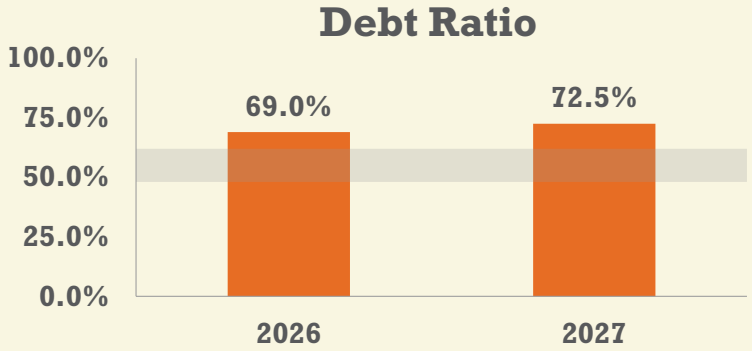
- **Purchased Power:** **$120 million** increase from 2026 budget
  - Market Purchases: Increasing as a result of load growth, placing more reliance on wholesale purchases
  - PPA / Capacity Contracts: Growth primarily driven by additional capacity; solar capacity (210 MW) and battery storage (85 MW)
- **Fuel:** Rising fuel prices and additional generation drive additional 2027 budgeted expenses of **$20 million**

DEBT AND DEBT RATIO*

$ IN MILLIONS







* *Total Debt Outstanding as a percentage of Total Capitalization at year end*

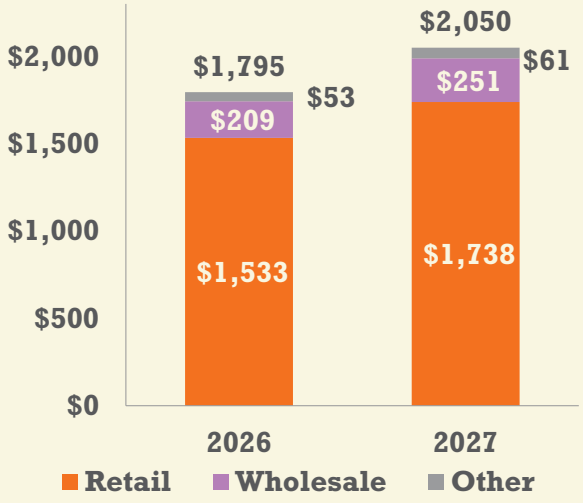
- Growing capital portfolio and investments in infrastructure is driving debt issuances
- Proceeds from the debt issuances ensure appropriate liquidity and days of cash on hand

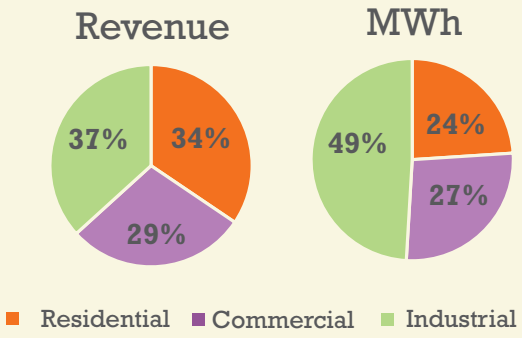
OPPD REMAINS IN A STRONG POSITION:

- Cash levels maintain the district's position in the AA-rated peer group for days cash on hand
- Debt ratio is currently above S&P's range of 50% to 60% for a very strong AA-rated utility

OPERATING REVENUE

$ IN MILLIONS







- District is experiencing revenue growth across all customer classes with Industrial class experiencing the largest growth rate
- Relative to 2026, load growth is budgeted to increase by approximately 10.8%

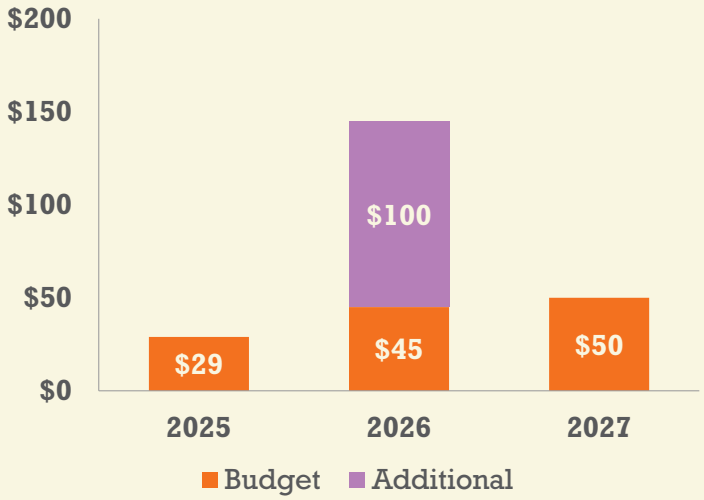
Retail Revenue*	2026	2027	Change
Residential	$572.3M	$596.9M	$24.6M
Commercial	428.5M	506.7M	78.2M
Industrial	543.7M	683.9M	140.2M
Total	$1,544.5M	$1,787.5M	$243.0M

**Excludes activity for Reserve Contributions/Usage and Fuel and Purchased Power Adjustment*

RETAIL RATE SMOOTHING

($ IN MILLIONS)





Year	Contribution / Withdrawal	Balance
2025	$29M	$29M
2026	$145M	$174M
2027	$50M	$224M

- OPPD is building reserves in advance of commercial operations of Cass County and Turtle Creek.
- This year, OPPD has the opportunity to increase reserves more than expected, further mitigating future rate increases
- 2027 contribution reflects continued strategy to build reserves to manage rate increases in a predictable, stable way
- Cost of new generation will hit the financial metrics in 2029 with commercial operations; reserve will prevent rate spikes

2027 RATE ACTION

2027 RATE ACTION

PROPOSED RATE INCREASE BY CUSTOMER CLASS

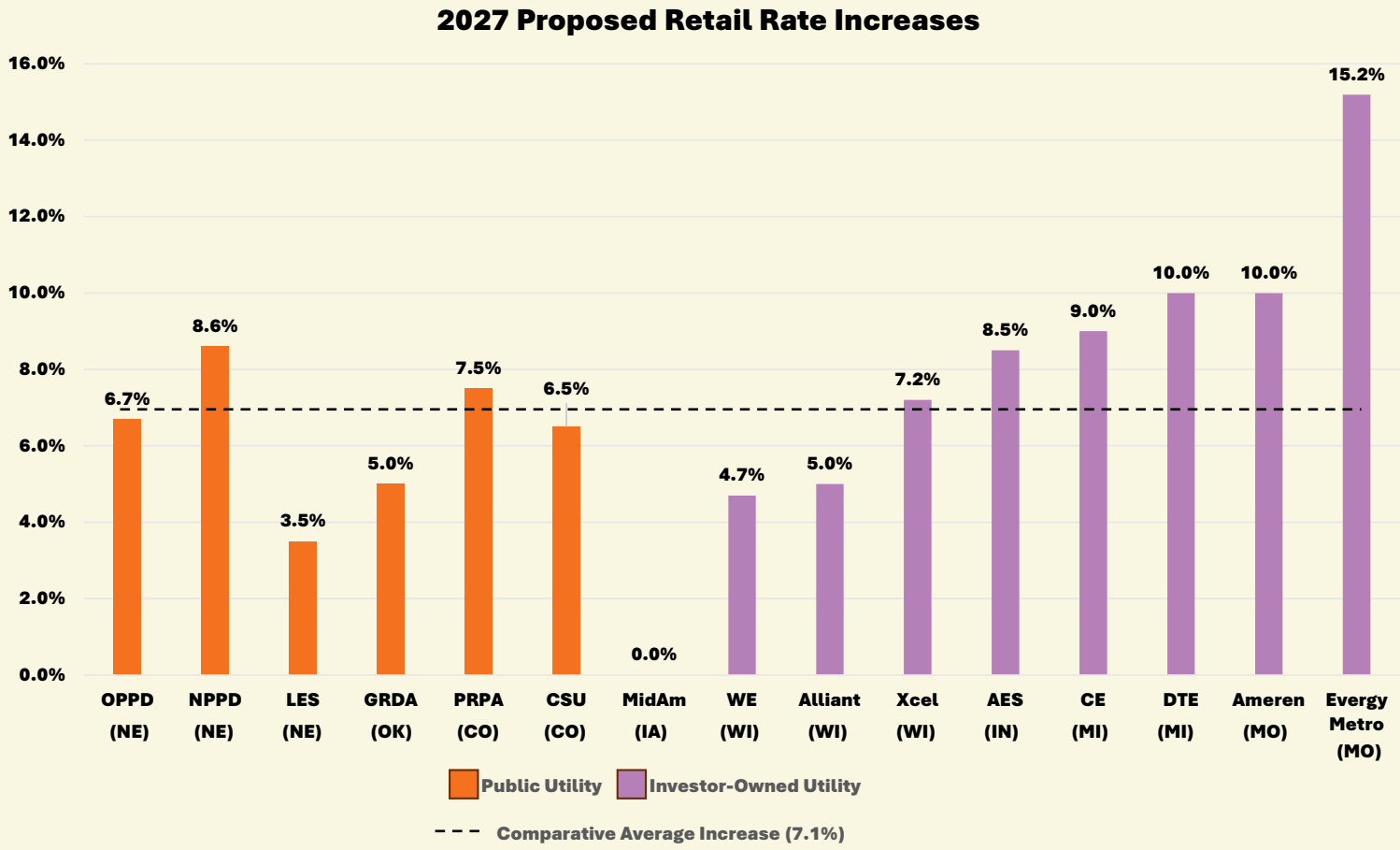
Proposed Percent Increase by Customer Class*							
	Residential	Commercial	Industrial	Hyperscale	Lighting	Wholesale	Total
Proposed General Increase	4.3%	7.6%	8.9%	13.0%	6.8%	5.4%	8.0%
Proposed FPPA Decrease	-1.3%	-2.0%	-2.4%	0.0%	-0.4%	-2.4%	-1.3%
Total Rate Action	**3.0%**	**5.7%**	**6.5%**	**13.0%**	**6.4%**	**3.0%**	**6.7%**

**The percentages represent class averages. Rates within each customer class will vary and individual customer impacts will differ based on usage.*

- **~94%** of **residential** customers will see an **increase** between **2-4%**
- **~68%** of **commercial**** customers will see an **increase** between **3-7%**
- **~80%** of **industrial**** customers will see an **increase** between **6-7%**
- All details regarding rate changes are presented in the redlined version of the Service Regulations and Schedules

** Includes 2027 Rate Increase and customer movement due to new C&I demand limits

Regional Rate Increases



RATE INCREASE FACTORS

- Improving Reliability/Grid Strengthening (NPPD, LES, CSU, AES, CE, DTE, Ameren, Evergy)
- Upgrading Outdated Infrastructure (NPPD, GRDA, CSU, Xcel, AES, Ameren, Evergy)
- Growing Generation and Energy Needs (NPPD, GRDA, CSU, WE, Alliant, Xcel)
- Moving Towards Sustainable Generation Portfolios (PRPA, Alliant, DTE)

2027 RATE ACTION

ADDITIONAL UPDATES

- **Rate 226: Irrigation:** Increasing single phase horsepower charge to $26.48
- **Rider 461**: **Fuel and Purchased Power:** Due to higher net power costs, the Base Rate will increase from 1.951 to 2.498 cents/kWh to recover the increase in the general rates
- **Rider 470F: Line Extension Charges (Residential):** Updated language for underground service
- **Rider 470H: Line Extensions and Temporary Service Disconnect charges (General Service):** Updated language for underground service
- **Rider 470I**: Tenant Attachment Fee: Pole attachments
  - **Current charge:** $18.00
  - **Proposed charge:** $19.00

2027 COP AND RATE ACTION

OUTCOMES FOR CUSTOMERS



Significant investments in the **distribution system,** including tree trimming and asset management to **keep service levels high**

Strengthening the organization's **digital capabilities** while keeping rates **competitive**

Confidence in a budget built on maintaining **financial strength**

NEXT STEPS

Our commitment to transparency and engagement



Proposed corporate operating plan available for **review and public comment online**

Board votes on proposed corporate operating plan

Any approved rate adjustments **go into effect January 1, 2027.**

QUESTIONS



2027 CORPORATE OPERATING PLAN

OPPD
Omaha Public Power District

OMAHA PUBLIC POWER DISTRICT
2027 CORPORATE OPERATING PLAN

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MANAGEMENT LETTER



OPPD made big strides in 2026 to upgrade, innovate and expand the many energy services our customers need and the ways they can monitor and manage their usage.

The change we've embraced, customer-facing and otherwise, is hard to overstate. As demand for electricity surges and customer expectations evolve, we at OPPD have worked proactively to meet those needs.

Our new customer portal, **MyOPPD,** is now running as both an app and a website. MyOPPD provides customers with tools to track their electricity usage, manage their accounts and receive updates during outages.

We continued our massive, multiyear rollout of advanced metering infrastructure (AMI). AMI is a collection of modern technology that allows direct, two-way communication between OPPD and individual customer meters. Over time, the new meters and supporting technology will offer customers faster and more precise outage information, a more detailed picture of their energy usage and other helpful tools.

AMI also will alert us when a customer loses power, allowing us to dispatch crews more quickly (though for now, please continue to report outages!). Utilities nationwide have already adopted the technology, with good results.

We are in the midst of major generation upgrades at two OPPD power plants to add much-needed generation and expand the capabilities of the facilities' existing units. And we're undertaking a historic expansion of our transmission network throughout our service territory, including the addition of 347-foot transmission towers – the tallest we've ever installed – at the Platte River in Louisville. This vital work will help ensure reliability and resilience for our rapidly growing customer demand.

Our work extends far beyond grid maintenance and technology upgrades.

Our annual energy assistance fundraiser, Heat the Streets Run & Walk for Warmth, generated $277,000 for assistance programs run by OPPD and the Metropolitan Utilities District.

We hosted numerous Community Resource Fairs throughout our territory to help connect families in need with assistance for necessities including food, housing, utilities and medical care.

In June, we sent a mutual aid team to eastern Illinois to help restore more than 220,000 utility customers who lost power after a major storm. These partnerships provide mutual benefits because other utilities will often return the favor when bad weather strikes Nebraska.

All of this comes as OPPD embraces generational growth and change. In July, as temperatures reached a sweltering 97 degrees, we logged a new peak demand of 3,285 megawatts. The longer-term trend is just as clear: As demand grows, we've set new summer peaks every year since 2021.

These demand pressures, coupled with supply-chain and labor shortages and inflation, have of course created challenges that we're working to address. We worked very diligently to keep rates as low as possible for residential users, our largest customer class. This year, we are recommending a 3% average rate increase for residential customers to help manage these growing expenses.

This proposal ensures OPPD has enough resources to ensure affordable, reliable service consistent with our Strategic Directives while recognizing the energy affordability considerations. We understand that rate increases can be difficult for customers, and we do not take that lightly.

For context, it's important to note that this rate pressure is industry-wide, yet OPPD's regional competitiveness has improved. Many non-Nebraska utilities are seeing double-digit increases. When I became CEO, our rates were 10% below the national average. Now, they're around 30% below.

No matter the challenge, we're dedicated as always to providing the kind of service that we would want for our families and fellow Nebraskans – because we are customers and community members as well. As your neighbors and friends, we will do our best every day to provide you with reliable, affordable and sustainable energy services.



L. Javier Fernandez
President and Chief Executive Officer



STRATEGIC DIRECTION AND ENTERPRISE RISK MANAGEMENT



STRATEGIC DIRECTION

To provide clear and transparent direction on behalf of OPPD's customer owners OPPD's publicly elected Board of Directors established fifteen strategic direction (SD) policies in 2015 to which OPPD is accountable. The policies guide OPPD's planning efforts to address current and future trends, mitigate risks, pursue strategic opportunities, and prioritize resources to efficiently and effectively provide energy services to our customer-owners. The SD policies leverage industry benchmarks to drive performance as a top utility and provide the basis for a scorecard to which the organization manages its performance. The Board monitors OPPD's compliance with these policies and updates the policies, when determined appropriate, to clarify strategic direction.

Our Strategic Foundation (SD-1)

Mission: To provide affordable, reliable and environmentally sensitive energy services to our customers.

Vision: "Leading the Way We Power the Future"

In implementing this vision, OPPD shall adhere to these principles:

- Strengthen the public power advantage of affordable and reliable electricity;
- Exemplify fiscal, social and environmental responsibility to optimize value to our customer-owners;
- Proactively engage and communicate with our stakeholders;
- Act transparently and with accountability for the best interest of our customer-owners;
- Collaborate, when appropriate, with partners; and
- Leverage OPPD's leadership to achieve these goals

Core Values

- We have a PASSION to serve
- We HONOR our community
- We CARE about each other

Policy	Measure	Definition	Strategic Goal
Rates (SD-2)	% Below Regional Retail Average	Retail rate target of West North Central Regional average published rates on a system average basis.	10%
Access to Credit Markets (SD-3)	Debt Coverage Ratio	Revenues less expenses divided by total annual senior and subordinate lien debt interest and principal payments.	2.0
Reliability (SD-4)	SAIDI	System Average Interruption Duration Index	Top Quartile < 90 Minutes
	SAIFI	System Average Interruption Frequency Index	Top Quartile < 0.9 Interruptions
	EFOR	Fleet Level Equivalent Forced Outage Rate	Mid-Second Quartile < 9%
Customer Satisfaction (SD-5)	Customer Satisfaction Index Ranking	Customer satisfaction for similar-sized utilities in the region across residential and business customers.	Top quartile
Safety (SD-6)	OPPD Safety Index	12 month rolling index with leading and lagging indicators in psychological and physical safety.	> or = 80%
Environmental Stewardship (SD-7)	% Net reduction in CO2e	Strive to achieve net zero carbon equivalent (CO2e) emissions by 2050 relative to OPPD's 2013 benchmark.	Achieve net zero CO2e by 2050
Employee Relations (SD-8)	Employee Engagement	Composite score of employee engagement	Top quartile = or > 72%

For a full listing of the 15 Strategic Directives, which includes Integrated System Planning (SD-9), Ethics (SD-10), Economic Development (SD-11), Information Management & Security (SD-12), Stakeholder Outreach & Engagement (SD-13), Retirement Plan Funding (SD-14), Enterprise Risk Management (SD-15), please access the following link to the OPPD Board Policy document https://www.oppd.com/media/317205/oppd-board-policy-binder.pdf

Powering the Future to 2050

At OPPD, we've imagined the future. Powering the Future to 2050 (PF2050) is a strategic vision to make OPPD cleaner, more sustainable, and more innovative than you can believe. While others have been wondering about what's next, we've been hard at work, nights and weekends, planning out what the future of power looks like and how to bring it to life. The vision is clear – **Perfect Power**, **Customer Freedom**, and a **Cleaner World** enabled through a **Digitally Driven**, **Purpose-Driven Culture**, and **Future-Ready Posture** mindset.

In November of 2019, the Board of Directors revised SD-7 (Environmental Stewardship) and established the goal to conduct all operations in a manner that strives for the goal of net-zero-carbon production by 2050. In consideration of this revision, other SD policies, and transformational changes within and outside the industry, the Executive Leadership Team (ELT) created PF2050, which provides a strategic vision for the organization through the year 2050. PF2050 outlines a transformational journey and was developed with the expressed intent to meet or exceed the fifteen SD policies. This vision will transform OPPD to a digital utility with two-way and multi-directional power and communication flows, build a proactive grid, give customer-owners multiple options, minimize environmental impact, and reduce carbon emissions. The future is coming, and we want to make sure it is illuminated.

Acknowledging the rapidly evolving and increasingly complex environment we operate in, OPPD adopted a future-ready posture mindset. This means we are taking a thoughtful approach to investing in both core work ('keeping the lights on today') and in the efforts to power our next generation. This deliberate and agile approach resulted in the establishment of the enterprise strategic priorities. Their requirements and aspirational futures are embedded in the very DNA of these priorities and serve as the foundation for everything we do. These priorities are fully aligned under PF2050 and directly inform the current year's budget, ensuring that OPPD's finite resources are deployed against the right work to move us toward our long-term objectives of Perfect Power, Customer Freedom, and a Cleaner World by 2050.

Powering the Future to 2050

OPPD leveraged PF2050 and the enterprise priorities to guide planning, prioritization, and resourcing decisions for this Corporate Operating Plan. The vision to meet the growing demands of the service territory is becoming a reality as we transition from strategic planning to resourcing the execution in service of our customer-owner requirements in 2030 and beyond. We will continue to build upon our resource prioritization & capacity management framework and strategic STEER trends and risk scanning capabilities that will result in new and better ways to deliver affordable, reliable, and environmentally sensitive energy services to our customer-owners. Additional information regarding PF2050 can be found on https://www.oppdcommunityconnect.com/pf2050.







ENTERPRISE RISK MANAGEMENT

Fundamental to effective planning is an understanding of the District's enterprise level risks and the development and implementation of initiatives and mitigation plans to respond to those risks. The District's Enterprise Risk Management (ERM) program specifies risk management standards, management responsibilities, and controls to help ensure risk exposures are properly identified and managed within agreed upon risk tolerance levels. Specific risk mitigation plans and procedures are maintained and reviewed periodically to provide focused and consistent efforts to mitigate various risk exposures. An increased focus on emerging risks, such as disruptive technology, was launched in 2023. This process will continue to strengthen executive leadership's understanding of these risks to ensure an optimal future-ready posture for the organization. In support of its 2027 corporate planning efforts, OPPD leveraged risk assessments and mitigation plans to help prioritize resource allocation. The ELT will continue to expand this effort by incorporating those critical trends identified and associated with PF 2050.

Theme	OPPD's Risk Management Focus
Cyber & Physical Security	Vigorously defend customer information, operational technologies, and assets against evolving cyber and physical threats facing national critical infrastructure. Strengthen detection, mitigation, and response capabilities to ensure continuity of service.
Technology & Digital Disruption	Deliver world-class execution of technology transformation initiatives that create a future-ready posture. Anticipate digital disruption, accelerate strategic innovation, and deploy technology solutions that enhance reliability, affordability, and value for customer-owners.
Infrastructure Resilience & Aging Assets	Optimally invest in transmission, distribution, substation, and facility assets to sustain reliability and resilience. Proactively manage aging infrastructure and strengthen system capability to meet growing customer demand with minimal service interruptions.
Resource Adequacy & Reliability	Acquire, operate, and maintain a diverse, high-availability generation portfolio that reliably serves significantly growing customer demand. Ensure sufficient capacity, operational flexibility, and planning rigor to support current and future energy needs.
Financial, Supply Chain, & Market Volatility	Persistently pursue customer and economic development to achieve economies of scale and maintain affordable rates. Optimize wholesale market interactions and manage fuel and supply chain portfolios through diversified strategies that reduce financial volatility.
Regulatory & Policy Compliance	Ensure the District remains compliant with all environmental, energy, and reliability regulations. Maintain agility to respond to new or changing policy requirements and continue minimizing environmental impact while advancing strategic initiatives.
Ethics, Litigation, & Legal Exposure	Maintain a strong ethical culture and robust governance practices that protect the organization from legal exposure. Ensure transparent decision-making, proactive compliance management, and effective mitigation of litigation risks.
Stakeholder & Public Trust	Honor the communities in which OPPD operates and fulfill the promise of public power. Strengthen trust through transparency, engagement, and responsiveness to stakeholder expectations while delivering reliable, affordable, and environmentally sensitive service.
Workforce Safety & Transformation	Promote safety as a top organizational priority, ensuring every employee and contractor returns home as healthy as they arrived. Advance workforce capability and transformation efforts to prepare employees for emerging technologies and evolving operational needs.



ASSUMPTIONS

Assumptions

2027 Proposed Rate Action

Effective January 1, 2027, Omaha Public Power District's (OPPD) 2027 Corporate Operating Plan incorporates a 6.7% average total rate adjustment across all customer classes. This adjustment comprises an 8.0% average general rate increase and a 1.3% decrease attributed to the Fuel and Purchased Power Adjustment (FPPA) factor. The general rate increase is driven primarily by an expanding capital investment portfolio requiring additional debt financing. The FPPA decrease results from OPPD's periodic reset of the base FPPA rate. As part of this process, certain ongoing power costs previously recovered through the FPPA factor are now incorporated into the base rate. While overall net power costs are rising, shifting these costs to the base rate causes the FPPA factor to decline, ensuring it continues to recover the variable costs of generating and purchasing power.

Rate adjustment by customer class:

- Residential: 3.0% average rate increase
- Commercial: 5.7% average rate increase
- Industrial: 11.0% average rate increase

Rate increases will vary both by rate class within a customer class and within a rate class based on individual customer usage.

General Overview

2026 Projected

Projected revenues, operations and maintenance expenses, capital investments, and deferred expenditures for 2026 are based on actuals and forecasts through September 30, 2026.

Financing and Investment Strategy

Debt Financing

The 2027 budget includes planned issuance of revenue bonds totaling $1,069.0 million. These funds will support capital expenditures and to ensure appropriate liquidity levels.

Earnings Rates on Funds

The average earnings rate applied to all funds, including those designated for special purposes, is budgeted at 4.2% for 2027. This represents a 0.8% increase from the prior year's rate of 3.4%.

Assumptions

Energy Sales and Revenue Forecast

Load Forecast

Retail energy sales are expected to increase 10.8% (measured in megawatt-hours), with a 1.8% increase in customer count in 2027 compared to the 2026 budget.

Generation and Purchased Power

Major planned outages for 2027 include base-load units at Nebraska City Station Units 1 and 2 and North Omaha Station Unit 5. Several shorter outages are also scheduled across other generating assets to support maintenance and reliability.

The purchased power budget reflects a diversified energy portfolio, including:

- **1,262 megawatts** of wind generation capacity
- **296 megawatts** of solar generation capability
- **80 megawatts** of hydropower sourced from the Western Area Power Administration
- **85 megawatts** of battery storage

Pierce County Energy Center is projected to come online in 2027 adding 210 megawatts of solar and 85 megawatts of battery storage.

Department Operations and Maintenance Budget

Departmental budgets were developed to align with OPPD's strategic and operational priorities. Final approval rests with the Board of Directors.

Assumptions

Capital Budget Expenditures

OPPD continues to refine its capital portfolio prioritization framework, emphasizing risk mitigation and downstream impacts associated with project deferrals. This approach aligns capital investments with strategic directives and enhances transparency through strengthened review and approval processes.

As system growth continues, capital expenditures increase accordingly to support reliability, modernization, and the addition of new generation resources.

Total 2027 Budget

The total proposed 2027 budget is **$3.4 billion**, supporting OPPD's mission and long-term service commitments.

BUDGET SUMMARY
(DOLLARS IN MILLIONS)

Total Budget

	BUDGET 2026	BUDGET 2027	INCREASE / (DECREASE)	% CHANGE
Capital Expenditures*	$ 1,190.0	$ 1,446.0	$ 256.0	21.5
Non-Fuel Operations & Maintenance	644.8	724.4	79.6	12.3
Fuel and Purchased Power	627.2	766.3	139.1	22.2
Total Debt Service and Other Expenses	228.6	306.0	77.4	33.9
Decommissioning Expenditures**	63.0	21.9	(41.1)	(65.2)
Payments in Lieu of Taxes	57.1	66.1	9.0	15.8
Reserves	44.5	50.0	5.5	12.4
Total Budget	**$ 2,855.2**	**$ 3,380.7**	**$ 525.5**	**18.4**

*Capital Expenditures are shown net of Contributions in Aid of Construction
**Decommissioning Expenditures represent expenditures related to Decommissioning activity, which differs from Decommissioning Funding ($11.7 million) which is an expense and is reflected on the income statement.

Budget Component Comparison

	BUDGET 2026	BUDGET 2027	CHANGE
Capital Expenditures*	41.7%	42.8%	1.1
Non-Fuel Operations & Maintenance	22.6%	21.4%	(1.2)
Fuel and Purchased Power	22.0%	22.7%	0.7
Total Debt Service and Other Expenses	8.0%	9.1%	1.0
Decommissioning Expenditures**	2.2%	0.6%	(1.6)
Payments in Lieu of Taxes	2.0%	2.0%	(0.0)
Reserves	1.6%	1.5%	(0.1)
Total Budget	**100.0%**	**100.0%**	**(0.0)**

Note: Variances in column totals reflect rounding of individual items.



FINANCIAL STATEMENTS

Coverage Ratios

Total Debt Service Coverage Ratio

OPPD's financial strategy is grounded in maintaining strong debt service coverage to ensure efficient and cost-effective access to credit markets. In alignment with **Strategic Directive SD-3: Access to Credit Markets**, the 2027 Corporate Operating Plan targets a **Total Debt Service Coverage Ratio (DSCR)** of **2.00 times**.

This focus on debt service coverage, rather than net income, reflects the District's commitment to fiscal discipline, creditworthiness, and financial resilience in the face of rising capital demands and evolving energy needs.

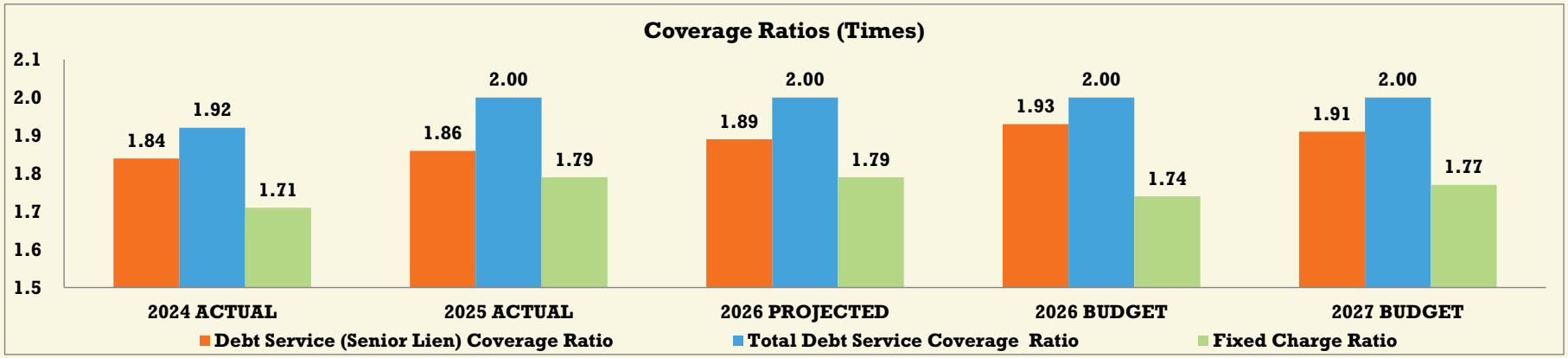
Fixed Charge Coverage Ratio

The fixed charge coverage ratio is budgeted to increase to **1.77 times** in 2027, up from 1.74 in 2026, reflecting a modest improvement in OPPD's ability to meet fixed financial obligations.

OMAHA PUBLIC POWER DISTRICT
2027 CORPORATE OPERATING PLAN

COVERAGE RATIOS
(DOLLARS IN MILLIONS)

	ACTUAL 2024	ACTUAL 2025	PROJECTED 2026	BUDGET 2026	VARIANCE 2026	BUDGET 2027	BUDGET CHANGE $	BUDGET CHANGE %
Operating Revenues (excluding NC2)	$ 1,437.9	$ 1,638.9	$ 1,847.2	$ 1,721.2	$ 126.0	$ 1,976.6	$ 255.4	14.8
Interest Income - Bonds Reserve Account	5.4	6.6	7.6	4.6	3.0	7.1	2.5	54.8
Payments in Lieu of Taxes	(45.7)	(52.6)	(59.2)	(57.1)	(2.1)	(66.1)	(9.0)	15.8
O&M Expense (excluding NC2 participant share)	(1,065.8)	(1,200.4)	(1,378.6)	(1,243.0)	(135.6)	(1,462.6)	(219.6)	17.7
Net Receipts	**$ 331.8**	**$ 392.5**	**$ 417.1**	**$ 425.7**	**$ (8.6)**	**$ 455.0**	**$ 29.3**	**6.9**
Total Debt Service Coverage Ratio (DSC)	**1.92**	**2.00**	**2.00**	**2.00**	**-**	**2.00**	**-**	**-**
Debt Service Requirements (Senior Lien)	$ 180.4	$ 211.1	$ 220.4	$ 220.3	$ 0.1	$ 237.2	$ 16.9	7.7
Debt Service (Senior Lien) Coverage Ratio	1.84	1.86	1.89	1.93		1.91		
Fixed Charge Ratio	1.71	1.79	1.79	1.74		1.77		



Note: Variances in column totals reflect rounding of individual items.
Total DSC as defined in OPPD's published Strategic Directive-3: Access to Credit Markets.

Capital Financing and Debt Structure

OPPD's 2027 Corporate Operating Plan reflects a disciplined approach to debt management, supporting strategic capital investments while maintaining strong financial metrics. OPPD will continue to evaluate outstanding debt for refinancing opportunities when financially prudent, with the goal of reducing interest costs and enhancing long-term financial flexibility.

Senior Lien Revenue Bonds

Total senior lien revenue bonds outstanding at year-end 2027 are budgeted at **$5,555.6 million**.

Key components include:

- Planned issuance of approximately **$1,069.0 million** in new senior lien revenue bonds.
- Scheduled maturities and retirements totaling **$68.3 million**.

Subordinated Bonds

No new subordinated bond issuances are planned. All previously issued subordinated bonds were either matured or retired in 2024.

Commercial Paper

Commercial paper outstanding at year-end 2027 is budgeted to increase to **$584.0 million**. The commercial paper portfolio is expanding to support our continued growth and increase liquidity flexibility through greater short-term funding capacity.

Separate System Nebraska City Unit 2 (NC2) Revenue Bonds

NC2 revenue bonds outstanding at year-end 2027 are budgeted at **$157.5 million**.

- No new NC2 bond issuances are planned
- Scheduled maturities and retirements total **$3.7 million**. During 2026, OPPD issued $156.5 million of 2026A Separate Electric System Revenue Bonds, refunding $180.4 million of prior debt and generating 4.1% present value savings.

Capital Financing and Debt Structure

Interest Rate and Capitalization Metrics

The average interest rate on existing debt is budgeted at **4.11%** by the end of 2027, an increase of 0.75% from the 2026 budget of 3.36%.

The debt-to-capitalization ratio is budgeted at **72.5%**, up from 69.0% in 2026, driven by new debt issuance supporting OPPD's capital program.

CAPITAL FINANCING AND DEBT STRUCTURE
(DOLLARS IN MILLIONS)

	ACTUAL 2024	ACTUAL 2025	PROJECTED 2026	BUDGET 2026	VARIANCE 2026	BUDGET 2027	BUDGET CHANGE $	BUDGET CHANGE %
Senior Lien Revenue Bonds								
Balance - Beginning of Year	$ 2,439.8	$ 3,061.4	$ 3,812.2	$ 3,818.1	$ (5.9)	$ 4,554.8	$ 736.7	19.3
New Issues	980.4	910.8	808.0	856.8	(48.8)	1,069.0	212.2	24.8
Maturities / Retirements	(358.8)	(160.0)	(65.4)	(79.2)	13.9	(68.3)	10.9	(13.8)
Balance - End of Year	**$ 3,061.4**	**$ 3,812.2**	**$ 4,554.8**	**$ 4,595.7**	**$ (40.9)**	**$ 5,555.6**	**$ 959.9**	**20.9**
Average Interest Rate (End of Year)	4.01%	4.18%	4.40%	4.15%		4.18%		
Subordinated								
Balance - Beginning of Year	134.7	-	-	-	-	-	-	-
New Issues	-	-	-	-	-	-	-	-
Maturities / Retirements	(134.7)	-	-	-	-	-	-	-
Balance - End of Year	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**-**
Average Interest Rate (End of Year)								
Commercial Paper								
Balance - Beginning of Year	250.0	250.0	250.0	250.0	-	584.0	334.0	133.6
New Issues	100.0	100.0	334.0	-	334.0	-	-	-
Maturities / Retirements	(100.0)	(100.0)	-	-	-	-	-	-
Balance - End of Year	**$ 250.0**	**$ 250.0**	**$ 584.0**	**$ 250.0**	**$ 334.0**	**$ 584.0**	**$ 334.0**	**133.6**
Average Interest Rate (End of Year)	4.44%	3.64%	3.25%	3.00%		3.25%		
Separate System Revenue Bonds (NC2)								
Balance - Beginning of Year	193.7	189.5	185.1	185.1	(0.0)	161.2	(23.9)	(12.9)
New Issues	-	-	156.5	-	156.5	-	-	-
Maturities / Retirements	(4.2)	(4.4)	(180.4)	(4.6)	(175.8)	(3.7)	0.9	(19.7)
Balance - End of Year	**$ 189.5**	**$ 185.1**	**$ 161.2**	**$ 180.5**	**$ (19.3)**	**$ 157.5**	**$ (23.0)**	**(12.8)**
Average Interest Rate (End of Year)	4.95%	4.95%	4.90%	3.89%		4.86%		
Total Average Interest Rate (End of Year)	**4.18%**	**4.18%**	**4.10%**	**3.36%**		**4.11%**		
Total Interest Expense (On Debt)	**$131.5**	**$139.2**	**$193.0**	**$144.8**	**$48.2**	**$234.0**	**$89.2**	**61.6**
Debt to Capitalization Ratio	**65.90%**	**67.50%**	**70.40%**	**69.00%**		**72.50%**		

Note: Variances in column totals reflect rounding of individual items.

Income Statement

OPPD prioritizes liquidity and debt service capacity over net income in alignment with Strategic Directive SD-3. Key drivers of budgeted operating results for 2027 include:

Operating Revenues

Total operating revenues are budgeted at **$2,049.5 million**, an increase of **$250.4 million** (13.9%) over the 2026 budget.

- Retail revenues are expected to increase by **$204.3 million** (13.3%) due to load growth and the general rate increase.
- Wholesale revenues are budgeted to rise by **$41.9 million** (20.0%), primarily due to increased congestion hedging revenues.

Operating Expenses

Operations and Maintenance (O&M) expenses are budgeted at **$1,490.7 million,** an increase of **$218.7 million** (17.2%) from 2026.

- Fuel and purchased power costs are expected to rise by **$139.1 million** (22.0%), driven by additional generation, higher purchase volumes to support growing load as well as an additional 210 megawatts of solar capability coming online in 2027.
- Additional O&M increases are largely driven by higher SPP fees as transmission infrastructure expands, increased tree-trimming needs, and added headcount to support ongoing operations.

Other Income (Expenses)

Other non-operating expense is budgeted at **$105.9 million**, an increase of **$71.2 million** (205.2%) from 2026.

Key components include:

- Investment Income increase of **$28.7 million**, largely driven by increased earnings rates on funds on deposit.
- Interest expense increases by **$89.2 million** (61.6%) due to additional interest expense on debt issuances coupled with higher borrowing rates.

OMAHA PUBLIC POWER DISTRICT
2027 CORPORATE OPERATING PLAN

INCOME STATEMENT
(DOLLARS IN MILLIONS)

	ACTUAL 2024	ACTUAL 2025	PROJECTED 2026	BUDGET 2026	VARIANCE 2026	BUDGET 2027	BUDGET CHANGE $	BUDGET CHANGE %
Operating Revenues								
Retail	$ 1,233.1	$ 1,361.1	$ 1,517.3	$ 1,533.2	$ (15.9)	$ 1,737.5	$ 204.3	13.3
Wholesale	222.1	294.3	343.9	209.0	134.9	250.9	41.9	20.0
Other Electric	52.9	55.3	69.2	57.1	12.1	61.3	4.2	7.4
Total Operating Revenues	**$ 1,508.1**	**$ 1,710.7**	**$ 1,930.4**	**$ 1,799.3**	**$ 131.1**	**$ 2,049.7**	**$ 250.4**	**13.9**
Operating Expenses								
O&M Expense	$ 1,099.9	$ 1,215.0	$ 1,472.4	$ 1,272.0	$ 200.4	$ 1,490.7	$ 218.7	17.2
Depreciation Expense	143.5	183.6	213.6	216.0	(2.4)	207.2	(8.8)	(4.1)
Decommissioning Expense	17.2	15.9	12.1	11.5	0.6	11.7	0.2	1.7
Total Operating Expenses	**$ 1,260.6**	**$ 1,414.5**	**$ 1,698.1**	**$ 1,499.5**	**$ 198.6**	**$ 1,709.6**	**$ 210.1**	**14.0**
Operating Income	**$ 247.5**	**$ 296.2**	**$ 232.3**	**$ 299.8**	**$ (67.5)**	**$ 340.1**	**$ 40.3**	**13.4**
Noncapital Subsidies								
Payments in Lieu of Taxes	$ 45.7	$ 52.6	$ 59.2	$ 57.1	$ 2.1	$ 66.1	$ 9.0	15.8
Other Noncapital Subsidies - Net	-	-	(52.1)	-	(52.1)	-	-	-
Total Noncapital Subsidies - Net	**$ 45.7**	**$ 52.6**	**$ 7.1**	**$ 57.1**	**$ (50.0)**	**$ 66.1**	**$ 9.0**	**15.8**
Total Operating Income and Noncapital Subsidies	**$ 201.8**	**$ 243.5**	**$ 225.2**	**$ 242.7**	**$ (17.5)**	**$ 274.0**	**$ 31.3**	**12.9**
Other Non-Operating Income (Expenses)								
Interest Expense	$ (131.5)	$ (139.2)	$ (193.0)	$ (144.8)	$ 48.2	$ (234.0)	$ (89.2)	61.6
Allowance for Funds Used During Construction	44.6	51.4	54.9	62.5	(7.6)	51.6	(10.9)	(17.4)
Investment Income	47.0	53.5	30.9	33.1	(2.2)	61.8	28.7	86.7
Decommissioning Funds - Investment Income	15.0	21.2	12.1	11.5	0.6	11.7	0.2	1.7
Other - Net	1.1	6.9	11.7	3.0	8.7	3.0	0.0	-
Total Other Non-Operating Income (Expenses)	**$ (23.7)**	**$ (6.3)**	**$ (83.4)**	**$ (34.7)**	**$ (48.7)**	**$ (105.9)**	**$ (71.2)**	**205.2**
Net Income	**$ 178.1**	**$ 237.2**	**$ 141.8**	**$ 208.0**	**$ (66.2)**	**$ 168.1**	**$ (39.9)**	**(19.2)**

Note: Variances in column totals reflect rounding of individual items.


ENERGY SALES

Electric Energy Sales and Customers

Total electric energy sales for 2027 are budgeted at **20,024,910 megawatt-hours (MWh)**, an increase of **1,197,389 MWh** (6.4%) compared to the 2026 budget.

Commercial & Industrial Demand Limits

In December 2025, the Board approved new Applicability standards for Commercial and Industrial customers, effective January 2027. These changes were intended to establish more clearly defined usage characteristics for determining eligibility in the Commercial and Industrial rate offerings. As a result, the new standards led to significant customer movement between the Commercial and Industrial classes in 2027. (These shifts will affect year-over-year comparisons for Retail Energy Sales, number of customers and kWh/Customer in the table below).

Retail Energy Sales

Retail energy sales are budgeted to increase **10.8%,** reaching **17,098,381 MWh** in 2027 driven by steady Residential growth and higher Commercial sales following customer reclassifications. Industrial sales growth is primarily due to large data center projects.

Wholesale Energy Sales

Wholesale energy sales, including NC2 participation sales, are forecasted to decline by **475,925 MWh** (14.0%) from the 2026 budget. The reduction is primarily due to increased retail load consuming a larger share of owned generation, thereby reducing the volume available for market-based wholesale transactions.

Retail Customer Growth

The average number of retail customers is projected to grow by **7,807**, an increase of **1.8%** compared to the 2026 budget. This expansion reflects continued population and economic growth within OPPD's service territory.

ELECTRIC ENERGY SALES AND CUSTOMERS

	ACTUAL 2024	ACTUAL 2025	PROJECTED 2026	BUDGET 2026	VARIANCE 2026	BUDGET 2027	BUDGET CHANGE MWh	BUDGET CHANGE %
Electric Energy Sales (MWh)								
Residential	3,860,697	4,010,631	4,056,746	4,056,721	25	4,090,115	33,394	0.8
Commercial	3,792,270	4,092,584	4,208,259	4,077,671	130,588	4,601,815	524,144	12.9
Industrial	5,784,043	6,927,894	7,954,601	7,263,993	690,609	8,256,854	992,861	13.7
Unbilled Revenue / Adjustments	44,227	152,175	1,563	26,682	(25,119)	149,597	122,915	460.7
Retail Energy Sales	**13,481,237**	**15,183,284**	**16,221,170**	**15,425,067**	**796,103**	**17,098,381**	**1,673,314**	**10.8**
NC2 Participant	1,742,965	1,958,534	2,533,811	2,063,637	470,174	1,771,419	(292,218)	(14.2)
Other	1,868,018	1,468,877	1,193,191	1,338,816	(145,625)	1,155,109	(183,707)	(13.7)
Wholesale Energy Sales	**3,610,983**	**3,427,411**	**3,727,002**	**3,402,453**	**324,549**	**2,926,528**	**(475,925)**	**(14.0)**
Total MWh Sales	**17,092,219**	**18,610,695**	**19,948,172**	**18,827,520**	**1,120,651**	**20,024,910**	**1,197,389**	**6.4**
Electric Customers (12 Month Average)								
Residential	362,919	368,729	374,478	373,563	915	380,621	7,058	1.9
Commercial	50,364	50,986	51,593	51,491	102	52,308	817	1.6
Industrial	131	105	100	104	(4)	36	(68)	(65.4)
Total Electric Customers	**413,414**	**419,819**	**426,171**	**425,158**	**1,013**	**432,965**	**7,807**	**1.8**
kWh / Customer								
Residential	10,638	10,877	10,833	10,860	(26)	10,746	(114)	(1.0)
Commercial	75,297	80,269	81,566	79,192	2,374	87,975	8,784	11.1
Industrial	44,153,003	66,242,807	79,878,842	69,846,084	10,032,758	229,357,048	159,510,963	228.4
Average kWh / Customer	**32,503**	**36,166**	**38,063**	**36,218**	**1,845**	**39,491**	**3,273**	**9.0**

Note: Variances in column totals reflect rounding of individual items.

Operating Revenues

Total electric operating revenues for 2027 are budgeted at **$2,049.7 million**, an increase of **$250.4 million** (13.9%) over the 2026 budget.

Retail Revenues

Retail revenues are budgeted to grow by **$204.3 million** (13.3%) over the prior year, driven by revenue growth across all customer classes and planned rate increases that reflect the rising cost of service and continued investment in infrastructure and new generation.

Wholesale Revenues

Wholesale revenues are expected to increase by **$41.9 million** (20.0%) relative to the 2026 budget. This growth is primarily attributed to higher congestion hedging revenues.

ELECTRIC OPERATING REVENUES
(DOLLARS IN MILLIONS)

	ACTUAL 2024	ACTUAL 2025	PROJECTED 2026	BUDGET 2026	VARIANCE 2026	BUDGET 2027	BUDGET CHANGE $	BUDGET CHANGE %
Electric Operating Revenues								
Residential	$ 477.0	$ 530.7	$ 566.7	$ 572.3	$ (5.6)	$ 596.9	$ 24.6	4.3
Commercial	370.4	410.8	435.5	428.5	7.0	506.7	78.2	18.2
Industrial	370.4	485.1	633.9	543.7	90.2	683.9	140.2	25.8
Unbilled Revenue / Adjustments	0.2	17.2	-	7.0	(7.0)	-	(7.0)	(100.0)
FPPA Revenue Adjustment	1.8	(40.4)	26.2	26.2	-	-	(26.2)	(100.0)
Use of (Contribution to) Reserves	13.3	(42.3)	(145.0)	(44.5)	(100.5)	(50.0)	(5.5)	12.4
Total Retail Sales	**$ 1,233.1**	**$ 1,361.1**	**$ 1,517.3**	**$ 1,533.2**	**$ (15.9)**	**$ 1,737.5**	**$ 204.3**	**13.3**
NC2 Participants	$ 70.2	$ 71.8	$ 83.2	$ 78.0	$ 5.2	$ 73.1	$ (4.9)	(6.3)
Other	151.9	222.5	$ 260.7	$ 131.0	$ 129.7	177.8	46.8	35.7
Total Wholesale Revenues	**$ 222.1**	**$ 294.3**	**$ 343.9**	**$ 209.0**	**$ 134.9**	**$ 250.9**	**$ 41.9**	**20.0**
Total Sales of Electric Energy	**$ 1,455.2**	**$ 1,655.4**	**$ 1,861.2**	**$ 1,742.2**	**$ 119.0**	**$ 1,988.4**	**$ 246.2**	**14.1**
Other Electric Revenues	52.9	55.3	69.2	57.1	12.2	61.3	4.2	7.4
Total Electric Operating Revenues	**$ 1,508.1**	**$ 1,710.7**	**$ 1,930.4**	**$ 1,799.3**	**$ 131.2**	**$ 2,049.7**	**$ 250.4**	**13.9**

Note: Variances in column totals reflect rounding of individual items.

Average Cents per Kilowatt-Hour (kWh)

The average retail price of electricity for 2027 is budgeted at **10.55 cents per kWh**, an increase of **0.52 cents** (5.1%) compared to the 2026 budget.

AVERAGE CENTS/kWh

	ACTUAL 2024	ACTUAL 2025	PROJECTED 2026	BUDGET 2026	VARIANCE 2026	BUDGET 2027	BUDGET CHANGE $	BUDGET CHANGE %
Residential	12.36	13.29	13.97	14.11	(0.14)	14.59	0.48	3.4
Commercial	9.79	10.05	10.35	10.51	(0.16)	11.01	0.50	4.8
Industrial	6.36	7.04	7.97	7.48	0.49	8.28	0.80	10.7
Retail Average*	**9.04**	**9.51**	**10.09**	**10.03**	**0.06**	**10.55**	**0.52**	**5.1**

Note: Variances in column totals reflect rounding of individual items.

* Average rates are from the revenue recognized on the Income Statement and do not incorporate accrued unbilled. These rates differ from customer billed rates and are calculated for benchmarking and illustrative purposes only.



NET SYSTEM REQUIREMENTS

Net System Requirements

For 2027, net system requirements—defined as total retail energy sales—are budgeted at **17,809,490 MWh**, an increase of **1,672,681 MWh** (10.4%) compared to the 2026 budget.

Sales Components

Total energy sales are budgeted to increase by **1,197,389 MWh** (6.4%) from the 2026 budget.

- Retail energy sales are budgeted to increase by **1,673,314 MWh** (10.8%).
- NC2 participant sales are expected to decrease by **292,218 MWh** (14.2%).
- Wholesale energy sales are forecasted to decrease by **183,707 MWh** (13.7%).

Supply Components

The largest change in supply for 2027 is an increase in wholesale purchases, which are budgeted to rise by **1,125,977 MWh** (24.5%).

This increase is partially offset by:

- A **50,480 MWh** decrease (1.0%) in purchased power agreements, and
- A **121,259 MWh** increase (1.2%) in generation.

NET SYSTEM REQUIREMENTS
SALES AND SUPPY COMPONENTS (MWh)

	BUDGET 2026	BUDGET 2027	INCREASE / (DECREASE)	% CHANGE
Sales Components				
Retail Sales	15,425,067	17,098,381	1,673,314	10.8
NC2 Participation Sales	2,063,637	1,771,419	(292,218)	(14.2)
Wholesale Energy Sales	1,338,816	1,155,109	(183,707)	(13.7)
Total Sales Components	**18,827,520**	**20,024,910**	**1,197,389**	**6.4**
Supply Components				
Generation	10,030,371	10,151,630	121,259	1.2
Purchased Power Agreements	4,912,198	4,861,718	(50,480)	(1.0)
Wholesale Purchases	4,596,693	5,722,670	1,125,977	24.5
Lost or Unaccounted For	(711,742)	(711,109)	634	(0.1)
Total Supply Components	**18,827,520**	**20,024,910**	**1,197,389**	**6.4**

Note: Variances in column totals reflect rounding of individual items.

NET SYSTEM REQUIREMENTS

	ACTUAL 2024	ACTUAL 2025	PROJECTED 2026	BUDGET 2026	VARIANCE 2026	BUDGET 2027	BUDGET CHANGE MWh	BUDGET CHANGE %
Generation	**7,547,930**	**9,153,280**	**9,947,873**	**10,030,371**	**(82,498)**	**10,151,630**	**121,259**	**1.2**
Purchases (MWh)								
Firm / Participation Purchases	4,293,132	4,820,037	4,645,119	4,912,198	(267,079)	4,861,718	(50,480)	(1.0)
Wholesale Purchases	5,696,615	5,054,760	5,988,637	4,596,693	1,391,944	5,722,670	1,125,977	24.5
Total Purchases	**9,989,747**	**9,874,798**	**10,633,756**	**9,508,891**	**1,124,864**	**10,584,388**	**1,075,496**	**11.3**
Total Input	**17,537,677**	**19,028,077**	**20,581,629**	**19,539,263**	**1,042,366**	**20,736,018**	**1,196,756**	**6.1**
Wholesale Energy Sales								
NC2 Participant	1,742,965	1,958,534	2,533,811	2,063,637	470,174	1,771,419	(292,218)	(14.2)
Other	1,868,018	1,468,877	1,193,191	1,338,816	(145,625)	1,155,109	(183,707)	(13.7)
Total Wholesale Energy Sales	**3,610,983**	**3,427,411**	**3,727,002**	**3,402,453**	**324,549**	**2,926,528**	**(475,925)**	**(14.0)**
Net System Requirements	**13,926,694**	**15,600,666**	**16,854,627**	**16,136,809**	**717,818**	**17,809,490**	**1,672,681**	**10.4**
Total Retail Sales	13,481,237	15,183,284	16,221,170	15,425,067	796,103	17,098,381	1,673,314	10.8
Energy Lost or Unaccounted For	445,456	417,383	633,457	711,742	(78,285)	711,109	(634)	(0.1)
Net System Requirements	**13,926,693**	**15,600,666**	**16,854,627**	**16,136,809**	**717,818**	**17,809,490**	**1,672,681**	**10.4**

PEAK LOAD (MW)								
Peak Load Excluding Demand Response	2,819	2,908	3,296	3,036	260	3,372	336	11.1
Load Factor (%) - Excluding Demand Response	56.4	61.2	58.4	60.7	(2.3)	60.3	(0.4)	(0.6)
Demand Response*	129	122	111	128	(17)	111	(17)	(13.5)
Peak Load Including Demand Response	2,690	2,786	3,185	2,908	277	3,261	353	12.1
Load Factor (%) - Reflects Demand Response	59.1	63.9	60.4	63.3	(2.9)	62.3	(1.0)	(1.6)

Note: Variances in column totals reflect rounding of individual items.

* Does not include voluntary demand response

OPERATIONS AND MAINTENANCE EXPENSE



Operations and Maintenance Expense

The District's total budgeted O&M expense for 2027 is **$1,490.7 million**, an increase of **$218.7 million** (17.2%) compared to the 2026 budget.

2027 Budget Compared to 2026 Budget

Purchased Power

Purchased power—including wind energy contracts—accounts for **36.0%** of total O&M expense and is budgeted at **$536.6 million**, an increase of **$119.3 million** (28.6%) over 2026.

This increase is primarily driven by higher purchase volumes required to meet budgeted customer load growth as well as the addition of 210 megawatts of solar capability.

Fuel

Fuel costs are budgeted at **$229.7 million**, up **$19.8 million** (9.4%) from the prior year.

Rising fuel prices and additional generation to support customer demand is the primary driver of the additional fuel costs in 2027.

Transmission and Distribution

Transmission and distribution expenses are budgeted at **$253.5 million**, an increase of **$54.9 million** (27.6%) over 2026.

This growth is primarily driven by higher SPP fees and increased tree-trimming.

Administrative and General

Administrative and general expenses are budgeted at **$205.6 million**, an increase of **$9.5 million** (4.8%).

The increase is driven by higher employee benefit costs, reflecting updated guidance for retirement plans and a health-benefit increase that exceeds the inflationary assumption.

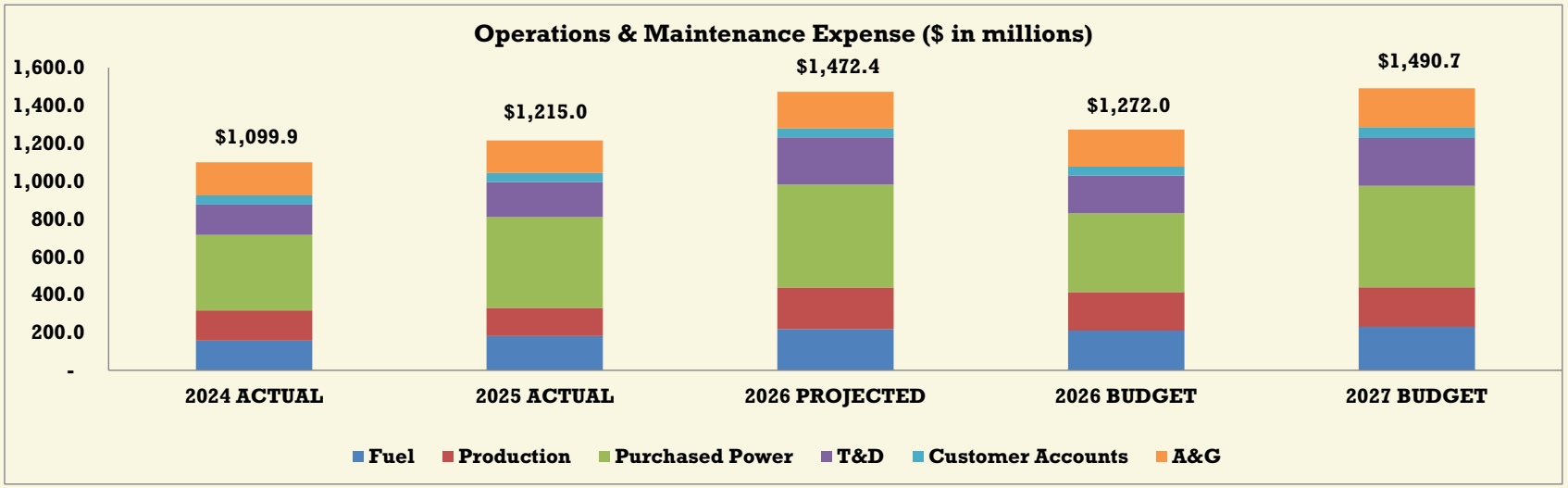
Production Expense

Production-related costs are budgeted at **$208.7 million**, an increase of **$5.3 million** (2.6%) compared to 2026.

Budgets reflect added operations and maintenance needs and associated payroll as the generation fleet expands.

OPERATIONS AND MAINTENANCE EXPENSE
(DOLLARS IN MILLIONS)

	ACTUAL 2024	ACTUAL 2025	PROJECTED 2026	BUDGET 2026	VARIANCE 2026	BUDGET 2027	BUDGET CHANGE $	BUDGET CHANGE %
Purchased Power	$ 399.4	$ 479.6	$ 543.4	$ 417.3	$ 126.1	$ 536.6	$ 119.3	28.6
Fuel	156.8	181.7	217.5	209.9	7.6	229.7	19.8	9.4
Fuel and Purchased Power	**$ 556.2**	**$ 661.3**	**$ 760.9**	**$ 627.2**	**$ 133.7**	**$ 766.3**	**$ 139.1**	**22.2**
Transmission and Distribution	$ 160.3	$ 184.9	$ 250.0	$ 198.6	$ 51.4	$ 253.5	$ 54.9	27.6
Administrative and General	175.5	172.0	193.2	196.1	(2.9)	205.6	9.5	4.8
Production	160.1	148.7	220.5	203.4	17.1	208.7	5.3	2.6
Customer	47.8	48.2	47.6	46.7	0.9	56.6	9.9	21.2
Total O&M Expense	**$ 1,099.9**	**$ 1,215.0**	**$ 1,472.4**	**$ 1,272.0**	**$ 200.4**	**$ 1,490.7**	**$ 218.7**	**17.2**
Decommissioning Expense	**$ 17.2**	**$ 15.9**	**$ 12.1**	**$ 11.5**	**$ 0.6**	**$ 11.7**	**$ 0.2**	**1.7**



Note: Variances in column totals reflect rounding of individual items.



CAPITAL EXPENDITURE PLAN

Overview

The 2027 capital budget is structured around three investment categories—**Sustain, Expand, and Strategic Priority**—to ensure balanced funding across asset maintenance, system growth, and transformational initiatives.

Sustain

These projects focus on maintaining and improving existing assets.

2027 Sustain capital expenditures are budgeted at **$376.8 million**, an increase of **$138.2 million** (57.9%) from the 2026 budget of $238.6 million.

Expand

Expand projects add new assets to support system load growth and economic development. 2027 Expand capital expenditures are budgeted at **$275.8 million**, an increase of **$84.7 million** (44.3%) over the 2026 budget.

Strategic Priority

Strategic Priority projects enable both reliable service today and the transformational capabilities needed to prepare for the future.

These expenditures are budgeted at **$793.3 million** in 2027, an increase of **$32.9 million** (4.3%) over the 2026 budget of $760.4 million.

Total Capital Budget

Total 2027 capital investment is budgeted at **$1.45 billion,** which represents **42.8%** of the total District budget.

This reflects a **$256.0 million** increase (21.5%) from the 2026 budget.

Functional Area Highlights

Transmission and Distribution (T&D)

T&D capital expenditures are budgeted at **$525.8 million**, an increase of **$140.4 million** (36.4%) from 2026.

The increase reflects expanded infrastructure to support new generation, major SPP transmission reliability projects, new economic development, and higher material costs.

Production

Production capital expenditures are budgeted at **$842.4 million**, an increase of **$138.1 million** (19.6%) over the 2026 budget of $704.3 million.

The increase is driven by continuing construction on new generation projects as well as investments to support reliability at existing generating facilities.

General

General capital expenditures are budgeted at **$100.0 million**, which is **$29.5 million** higher (41.8%) than the 2026 budget.

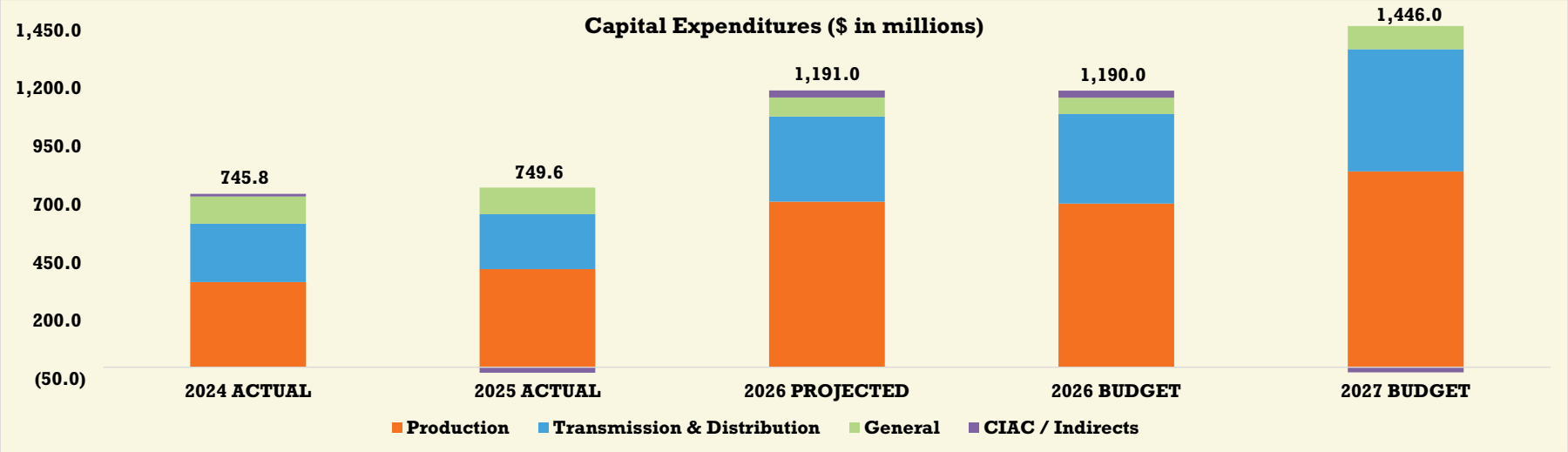
The increase is driven by additional spending on fleet vehicles for replacements along with higher facilities investments across the District.

OMAHA PUBLIC POWER DISTRICT
2027 CORPORATE OPERATING PLAN

CAPITAL EXPENDITURES
(DOLLARS IN MILLIONS)

	ACTUAL 2024	ACTUAL 2025	PROJECTED 2026	BUDGET 2026	VARIANCE 2026	BUDGET 2027	BUDGET CHANGE $	BUDGET CHANGE %
Transmission and Distribution	$ 251.5	$ 236.3	$ 366.9	$ 385.4	$ (18.5)	$ 525.8	$ 140.4	36.4
Production	366.5	422.3	712.3	704.3	8.0	842.4	138.1	19.6
General	116.9	114.8	82.0	70.5	11.5	100.0	29.5	41.8
Total Direct Capital	**$ 734.9**	**$ 773.4**	**$ 1,161.2**	**$ 1,160.2**	**$ 1.0**	**$1,468.2**	**$ 308.0**	**26.5**
Indirect Capital Expenses	$ 31.2	$ 14.1	$ 59.8	$ 59.8	-	$ 67.8	$ 8.0	13.4
Contributions in Aid of Construction	(20.3)	(37.9)	(30.0)	(30.0)	-	(90.0)	(60.0)	200.0
Contributions in Aid of Construction / Indirects	**$ 10.9**	**$ (23.8)**	**$ 29.8**	**$ 29.8**	**$ -**	**$ (22.2)**	**$ (52.0)**	**(174.5)**
Total Capital Expenditures	**$ 745.8**	**$ 749.6**	**$ 1,191.0**	**$ 1,190.0**	**$ 1.0**	**$ 1,446.0**	**$ 256.0**	**21.5**

Note: Variances in column totals reflect rounding of individual items.



OPPD Omaha Public Power District

CAPITAL EXPENDITURES (DIRECT)
SIGNIFICANT PROJECT DESCRIPTIONS AND HIGHLIGHTS
(DOLLARS IN MILLIONS)

RECOMMENDED PROJECTS:	2026 FORECAST	2027 BUDGET
Near Term Generation OPPD's near-term generation and transmission investments support Board Resolution No. 6582, approved August 15, 2023, to ensure reliability, resource adequacy, and infrastructure readiness.	$626.3	$556.6
Circuit and Substation Upgrades Circuit and substation upgrades are planned to support the expansion of transmission and distribution infrastructure, ensuring system reliability and capacity for future growth.	172.8	122.2
AMI - Smart Grid The AMI – Smart Grid initiative includes investments in advanced metering infrastructure technology to enable real-time data, enhance grid reliability, and support customer energy management.	12.3	56.0
Transformer Purchases and Replacements Transformer purchases and replacements are planned to modernize aging infrastructure and ensure capacity to meet growing customer demand.	38.3	39.1
Midtown Transmission Expansion The Midtown Transmission Expansion project increases transmission capacity to support load growth in the midtown area, ensuring reliable service for surrounding customers.	3.0	37.5
Transportation Fleet Replacement The Transportation Fleet Replacement program involves the routine renewal of OPPD-owned vehicles and equipment, including light, medium, and heavy-duty trucks and construction machinery, to maintain operational efficiency and safety.	17.4	27.8
Asset Management Plan - Cable Replacement The Transmission Distribution Improvement Program includes performance-based replacement of the worst-performing underground distribution cables to enhance system reliability and efficiency.	19.5	22.2

CAPITAL EXPENDITURES (DIRECT)
SIGNIFICANT PROJECT DESCRIPTIONS AND HIGHLIGHTS
(DOLLARS IN MILLIONS)

RECOMMENDED PROJECTS:	2026 FORECAST	2027 BUDGET
Sarpy County 3 Major Overhaul The Sarpy County 3 Major Overhaul project involves Siemens-recommended disassembly and inspection of key generator components to ensure continued reliability, identify potential issues, and extend the unit's operational lifespan.	$3.3	$21.0
Customer Service Commercial and Industrial Project The Customer Service Commercial and Industrial Project includes the purchase and installation of underground or overhead infrastructure to support the service needs of commercial and industrial customers.	18.8	20.5
Subscription Software Renewals Subscription Software Renewals include the ongoing renewal of licensed software essential for the District's business operations, ensuring continuity, security, and access to current technology platforms.	11.9	18.3
Customer Service Residential Project The Customer Service Residential Project includes the purchase and installation of underground or overhead infrastructure to serve new residential developments and support continued growth in the District's service territory.	16.4	16.8
Ground Line Inspection and Treatment Pole Replacement Ground line inspection and treatment efforts include replacing degraded wood poles and transmission structures to maintain safety, reliability, and system integrity.	13.6	15.4
Asset Management Plan - Conductors The Transmission Distribution Improvement Program includes performance-based replacement of deteriorated conductors to enhance reliability and reduce outage risk across the distribution system.	7.0	15.2

CAPITAL EXPENDITURES (DIRECT)
SIGNIFICANT PROJECT DESCRIPTIONS AND HIGHLIGHTS
(DOLLARS IN MILLIONS)

RECOMMENDED PROJECTS:	2026 FORECAST	2027 BUDGET
Joint Transmission Interconnection Queue (JTIQ) JTIQ is a major set of bulk electric system projects designed to expand transmission capacity along the north–south corridor of the Southwest Power Pool (SPP), enhancing regional reliability and access to generation resources.	$2.6	$14.9
Transmission and Distribution Street & Highway Project The Transmission and Distribution Street & Highway Project involves relocating OPPD facilities situated in public rights-of-way to accommodate municipal street and highway improvements.	12.1	13.1
Sarpy County Shop and Control Room The Sarpy County Shop and Control Room project includes construction of a new shop and administration building, along with expansion of the station's control room, to support ongoing operations and maintenance activities at Sarpy County Station	0.4	12.3
Papillion Waste Water Treatment Plant The Papillion Waste Water Treatment Plant project includes construction of a new substation and associated distribution circuits to serve the facility, ensuring reliable electric service for this critical municipal infrastructure.	4.6	11.7
Bellevue Transmission Redesign The Bellevue Transmission Redesign project enhances the reliability and resiliency of the transmission system serving the Bellevue area, supporting long-term grid performance and customer service continuity.	1.8	8.3
Energy Control Center Upgrades Energy Control Center Upgrades address identified deficiencies necessary to maintain compliant and reliable operation of the Energy Control Center, ensuring continued support for system monitoring and grid operations.	-	7.1
Transmission and Distribution Street Light Project The Transmission and Distribution Street Light Project involves relocating OPPD street light facilities located within public road rights-of-way to accommodate municipal infrastructure improvements and ensure continued service.	6.5	7.0

CAPITAL EXPENDITURES (DIRECT)
SIGNIFICANT PROJECT DESCRIPTIONS AND HIGHLIGHTS
(DOLLARS IN MILLIONS)

RECOMMENDED PROJECTS:	2026 FORECAST	2027 BUDGET
Expansion of Compute Storage The expansion of compute storage provides additional real-time computing capacity to accommodate load growth, improve system performance, and support OPPD's enterprise technology initiatives.	$3.9	$7.0
Arbor Railroad Line Improvements The Arbor Railroad Line Improvements include replacing and repairing bridges, ties, ballast, rail, and crossings along the OPPD-owned Arbor Rail line to ensure safe and reliable transport infrastructure.	13.2	6.9
Energy Market Trading System OPPD will migrate its Energy Market and Trading processes to align with industry standards, enhancing efficiency, transparency, and integration with regional market operations.	15.2	6.5
Bee Line Generation Solar The Bee Line Generation Solar project includes construction of a new substation southeast of Tekamah to interconnect the Bee Line Solar facility, supporting the integration of additional renewable generation into the OPPD system.	1.7	6.2

Brattle

Board of Directors
Omaha Public Power District
1919 Aksarben Drive
Omaha, Nebraska 68106

November 11, 2026

Ladies and Gentlemen:

The Omaha Public Power District ("the District") proposes a general rate increase of 8.0 percent effective January 1, 2027. Consistent with its policy of aligning rates with costs, the proposed percentage increase in base rates varies among customer classes. In addition to the general rate increase, the District proposes a downward adjustment to the fuel and purchase power adjustment ("FPPA") factor, resulting in a decrease in FPPA revenues of 1.3 percent as a share of the total revenue requirement. The combination of the general rate increase and the reduction in the FPPA factor results in an effective average rate increase of 6.7 percent.

I. Discussion

OPPD's proposed increase of 6.7 percent is based on the District's cost of service study ("COSS"). The primary purpose of a COSS is to allocate the costs of providing service to different customer classes based upon cost causation principles and the costs that each customer class imposes on the system. It aims to determine the portion attributable to each Rate Class under the principle of cost-causation. We have worked closely with the District on its COSS, including reviewing the methodology and associated spreadsheets. There are two overarching factors driving the variation in the rate increase by customer class for the 2027 year. The first reflects recent legislation in Nebraska, LB1010, that affects the allocation of incremental system costs triggered by large load growth. The second change pertains to recent proposed changes in the District's methodology to calculate the FPPA factor.

A. LB 1010 and Its Impact on Cost Allocation

Nebraska's LB 1010 establishes requirements for serving new or expanded customer loads exceeding 20 MW and expressly authorizes public power suppliers to establish rates that allocate system costs and associated risks to these customers. Consistent with this authority, the District has revised its allocation of costs associated with new generation investments in the future. Specifically, the District is proposing to allocate the costs of associated new generation among the different customers classes based on their respective shares of *expected energy and demand growth* through 2029, which is when new generation is expected to commence service.

B. FPPA Adjustment

The District's FPPA rate consists of two components. The base rate represents the portion of fuel and purchased power costs recovered through general energy rates, while the FPPA factor recovers the difference between expected costs and that base. For 2027, the District proposes increasing the base rate from 1.951 cents/kWh to 2.497 cents/kWh to incorporate higher ongoing costs into general rates. The resulting FPPA factor declines from 0.521 cents/kWh to 0.326 cents/kWh. This reset places a greater share of expected costs in general rates and reduces reliance on the separate adjustment.

The District also proposes recognizing the capacity value of purchased power agreements ("PPA") and removing Auction Revenue Rights ("ARR") and Transmission Congestion Rights ("TCR") revenues and costs from the FPPA calculation for both off-system sales and purchased power. PPAs were previously classified as energy only. The District is now proposing to classify the capacity portion of PPAs to demand. Th change in classification improves the treatment of purchased power costs, aligning the FPPA more closely with the underlying driver of those costs. The adjustment to the FPPA calculation for ARR and TCR provides greater risk mitigation flexibility to the District.

Finally, the District projects a $72 million FPPA over-collection for 2026, primarily attributable to congestion hedging revenues exceeding budgeted levels. The District proposes using it to support an additional $70 million Debt Retirement Account contribution in 2026, instead of refunding this amount back to the customers. This approach supports financial metrics and helps moderate future rate increases as debt service obligations rise.

II. Findings

We have reviewed the District's proposed rate increase and the accompanying calculations. The updated COSS methodology appropriately recognizes the greater cost responsibility of customer classes whose projected load growth is driving incremental generation investment. By allocating costs related to new generation based on each class's expected contribution to energy and demand growth, the District more closely aligns recovery of these costs with the underlying drivers for new generation. We find this approach reasonable and consistent with the cost allocation objectives of LB 1010.

We also find the two proposed changes to the FPPA methodology reasonable. The first, which classifies capacity driven PPA costs to demand is consistent with the principle of cost causation. The second, which proposes to remove congestion hedging revenues from the FPPA calculation reduces variability in the FPPA factor while enabling risk mitigation for the District. Relatedly, the proposed base rate reset appropriately incorporates ongoing fuel and purchased power costs into general rates, reducing reliance on the FPPA factor for their recovery. Overall, we find the District's proposed rate changes to be fair, reasonable and non-discriminatory.

Sincerely,



Sanem Sergici

PRINCIPAL | BOSTON

Typist (Initials Only)

Board of Directors
Omaha Public Power District
1919 Aksarben Drive
Omaha, Nebraska 68106

October 23, 2026

Ladies and Gentlemen:

As requested by the Board of Directors and Management of the Omaha Public Power District (the "District" or "OPPD"), The Brattle Group is to review the 2027 Corporate Operating Plan ("COP") prepared by the District. This letter serves as an interim update to the Board Members about our review of the Preliminary COP for 2027.

The District provided a Preliminary COP presentation outlining its proposed 2027 budget and plans for the upcoming calendar year. Following our review of these materials, we submitted a detailed set of questions to the District and received thorough and responsive answers that helped clarify key aspects of the proposed budget and planned activities. Based on the information and supporting data reviewed to date, we find the preliminary materials to be reasonable and have not identified any significant issues or areas of concern.

As of the date of this letter, our review of the Final 2027 COP remains outstanding. Once the final COP becomes available and our review is complete, we will prepare and submit our final letter report to the Members of the Board, including any additional findings or observations that may arise.

We appreciate the opportunity to serve the District. If you have any questions concerning this preliminary review, we will gladly discuss them with you at your convenience.

Sincerely,



Sanem Sergici

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Exhibit A
Proposed Rate Adjustments
January 1, 2027

	Proposed Revenue Increase ($ M)	Proposed Percent Increase
	Total	Total
Residential		
Residential	$14.8	3.0%
Conservation (Heat Pump Rate)	$2.5	3.0%
Total Residential	$17.3	3.0%
Commercial		
Irrigation Service	$0.0	0.0%
General Service Non-Demand	$6.1	5.0%
General Service Small Demand	$19.8	6.0%
Total Commercial	$25.9	5.7%
Large Commercial/Industrial		
General Service – Large Demand (over 1,000 kW)	$4.1	6.5%
Large Power (over 10,000 kW)	$8.1	6.5%
Large Power – High Voltage Transmission Level – Market Energy	$54.2	13.0%
Total Large Commercial/Industrial	$66.4	11.0%
Lighting		
Dusk-to-Dawn Lighting	$0.2	6.5%
Municipal Service – Street Lighting	$1.5	6.5%
Municipal Service –Traffic Signals and Signs	$0.0	0.0%
Total Lighting	$1.7	6.4%
Municipal Service	$0.1	3.0%
TOTAL*	$111.4	6.7%

* Totals may not add due to rounding.

Exhibit B
Proposed Service Regulations and Schedules Revisions
January 1, 2027

Rate Schedules	Description	Proposed Provision(s)
Service Regulations	Application for Rate Schedules	Update language for General Service Customers consistent with new Applicability standard that take effect 01/01/2027 (Approved in Resolution 6743)
Rate 226	Irrigation Service	Increase the Single-Phase Annual Connected Load Charge from $23.32 to $26.48 per horsepower
Rider 461	Fuel and Purchased Power Adjustment	Increase the Fuel and Purchased Power Base Rate from 1.951 cents per kilowatt-hour to 2.497 cents per kilowatt-hour
Rider 470F	Line Extension Charges (Residential)	Update language and various rates associated with extending electric service to new Residential customers
Rider 470H	Line Extensions and Temporary Service Disconnects Charges (General Service)	Update language and various rates associated with extending electric service to new General Service customers
Rider 470I	Tenant Attachment Fee	Update annual fee from $18.00 to $19.00.



Service Regulations & Schedules

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OPPD

Omaha Public Power District

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OVERVIEW

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INTRODUCTION AND DEFINITIONS

Introduction

Omaha Public Power District (OPPD) proudly provides affordable, reliable and environmentally sensitive energy services to Customers across a 13 county, 5,000 square mile service territory. Formed in 1946, OPPD is a public power utility and is governed by a publicly elected Board of Directors. The costs of providing service determines the Rates and Riders in this document.

These Service Regulations will guide both you and OPPD throughout your experience as a Customer, including the requirements of both OPPD to deliver and you to receive Electric Service. The OPPD Board of Directors has officially adopted these Service Regulations, and they may be revised, amended, superseded, or repealed at any time by the Board. Where applicable within these Service Regulations, reference will be made to additional OPPD documentation that provides more detailed requirements.

As a public power district in the State of Nebraska, OPPD has a defined Service Area and operates under applicable state laws, including the following:

Statutory Authority

Section 70-655, Revised Statutes of Nebraska, as amended, states that the Board of Directors of the Omaha Public Power District shall have the power and be required to fix, establish, and collect adequate rates, tolls, rents, and other charges for electrical energy and for any and all other commodities supplied by OPPD, which rates, tolls, rents, and charges shall be fair, reasonable, nondiscriminatory, and so adjusted as in a fair and equitable manner to confer upon and distribute among the users and Customers of commodities and services furnished or sold by OPPD for the benefits of successful and profitable operation and conduct of OPPD's business.

Section 70-1017, Reissue Revised Statutes of Nebraska, 1943, as amended, states any supplier of electricity at retail shall furnish service, upon application, to any applicant within the Service Area of such supplier if it is economically feasible to service and supply the applicant. This "obligation to serve" requires OPPD to make substantial investments in generation, transmission, distribution, and other property, facilities, and equipment, and the economic feasibility of such investments are based on the principle that the rates and other charges for Customers requesting such service will recover the cost of such investments and confer on OPPD and its customers the "benefits of a successful and profitable operation and conduct" of OPPD's business, as provided in Section 70-655. This "obligation to serve" also means that the Customer has an obligation to purchase and pay for service from OPPD, during the operation of the Customer's facilities within OPPD's service territory, so that OPPD may recover the cost of the investments made to provide Electric Service.

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Using This Document

Customers have differing Electric Service requirements based on their usage. OPPD has several rate offerings varying in structure, price, and complexity available to Customers to meet their needs. This document provides the specific Board of Directors approved language for each of these Rates, Service Regulations, and Riders. Please note that capitalized terms used in the Service Regulations are defined in the Definitions section.

To make it easier to find information within this document, the three main sections of this document are described below.

- SERVICE REGULATIONS
  This section informs the Customer of rules and regulations required to receive Electric Service from OPPD.

- RATE SCHEDULES
  This section outlines the available rates that Customers may select for receiving service from OPPD based on their usage characteristics and equipment requirements. These Rate Schedules include the billing components that describe the rates, fees, and/or charges for Electric service received from OPPD. All Customers must be covered by one of these Rate Schedules per Point of Delivery.

- RIDER SCHEDULES
  This section outlines all Rider Schedules applicable to Customers who receive service on an OPPD Rate Schedule. Riders can be elective or required based on Customer's Electric Service requirements and usage characteristics. Riders are additional fees, credits, or other charges where applicable to Customers based on the outlined criterion.

Understanding Billing Components

While there are multiple billing components, most rates have three primary billing components: Monthly Service Charge, Energy Charge, and Demand Charge. These components reflect the type of Electric Service provided to the Customer and are used to calculate a total electric bill. Not all rates have all three of these components and some rates have additional components based on their particular structure.

- MONTHLY SERVICE CHARGE
  This charge is a fixed amount required for a Customer to receive Electric Service. This amount does not vary with the amount of energy used. As an example, the Monthly Service Charge includes items such as Customer service, metering, and the infrastructure that connects a Customer to the electric grid.

- ENERGY CHARGE
  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 renewable energy purchases.

- DEMAND CHARGE
  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 costs to maintain infrastructure, such as power plants and transmission lines, whose sizing must meet all of OPPD's Customers' maximum usage year-round. For rates without Demand Charges, the Energy Charge covers these costs.

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Table of OPPD Rate Schedules and Applicable Rider Schedules

Customer Categories	Rate Schedules (subject to applicability)		Billing Components				Rider Schedules (subject to applicability, requirements, or other charges)
			Service Charge	Energy Charge	Demand Charge	Other	
Residential Service	110	Residential Service	●	●			355, 461, 483, 500
	115	Residential Conservation Service	●	●			355, 461, 483, 500
	120	Residential Service – TOU Pilot	●	●			355, 461, 483, 500
Small General Service (Less Than 3,000~~1,000~~ kW)	226	Irrigation Service		●		●	355, 461, 483
	230	General Service Non-Demand	●	●			355, 461, 483, 500
	231	General Service – Small Demand	●	●	●		355, 461, 462, 464, 467 (E, H, L, V), 469, 469S, 483, 500
Large General Service (More than 3,000~~1,000~~ kW)	232	General Service – Large Demand	●	●	●		355, 461, 462, 464, 467 (E, H, L, V), 469, 483, 484, 500
	245	~~Large Power – Contract~~Large Power	●	●	●		355, 461, 464, 467 (E, H, L, V), 469, 483, 484, 500
Very Large General Service (Transmission Interconnected)	261M	Large Power – High Voltage Transmission Level market Energy	●	●	●	●	355, 464, 467 (E, H, L, V), 483, 500
Lighting Service	236	Private Outdoor Lighting				●	461
	350	Municipal Service – Street Lighting				●	461
	351	Municipal Service – Traffic Signals and signs		●		●	461
Municipal Service	357	Municipal Service	●	●	●		355, 461, 484

Other relates to specific charges related to specific applications such as irrigation and lighting.

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DEFINITIONS

Auxiliary Generating Unit	A Customer operated generating unit that is used only to provide standby power to replace power normally supplied by a Primary Generating Unit.
Billing Demand	Demand as calculated in the Determination of Demand section and applied to the bill of a Customer who takes service under OPPD's Demand Rate Schedules.
Cogeneration	Concurrent production of electric energy and thermal energy used for heating or cooling purposes.
Curtailable Load	A Customer's Load contracted to be reduced during periods identified by OPPD.
Curtailable Customer	A Customer who has contracted to curtail Load according to the provisions of Rate Schedules 467, 467E, 467H, 467L or 467V.
Customer	Any person, partnership, association, firm, corporation (public or private), limited liability company, governmental agency, or other entity taking service from OPPD at a specific location, whether the service at that address is in their name or some other name.
Customer Owned Generation (COG)	Distributed Generation (DG) not owned and operated by a Nebraska electric utility, but typically owned and operated by a Customer of the utility.
Demand	The instantaneous rate at which energy is delivered to an electrical Load and measured in either kilowatts (kW) or kilovolts-amperes (kVA).
Demand Meter	The device(s) and any auxiliary equipment, including Demand registers, required to measure the Electric Service or to measure the 15-minute period of highest electrical energy consumption supplied by OPPD to a Customer at a Point of Delivery.
Demand Response (DR)	Customer adjustment or control of their electrical Load in response to a signal from the electric utility. Customers with DR capability are typically voluntary participants in special utility DR rate programs.
Demand Side Management (DSM)	See Load Management.
Distributed Energy Resource (DER)	Includes Distributed Generation (DG) and may generally include Load Management and Demand Response technologies.
Distributed Generation (DG)	Electric generation and/or Energy Storage technologies, generally characterized as 'distributed' in nature and interconnected to a utility distribution system at or near Customer Loads. DG may consist of one or more generators or resources. Energy sources used by DG to generate electricity may be from renewable or non-renewable sources.
Electric Service	The service by which OPPD supplies power to a Customer's Point of Delivery, either by overhead or underground wires.

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Emergency Generating Unit	A Customer-operated generating unit that is normally only used during an outage of the Electric Service from OPPD, for testing, or during curtailment by a Curtailable Customer.
Energy Storage	Technologies, including but not limited to battery storage, capable of controlled charging and discharging of electrical or other forms of energy, which may be applied in a number of ways to interact with an electrical system.
Federal Holidays	An authorized holiday recognized by the United States government.
NERC Holidays	North American Electric Reliability Corporation (NERC) defined holidays which include New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day.
General Service	Service to any Customer for purposes other than those included in the applicability provisions of the Residential Rate Schedules.
Load	Devices or appliances which consume electrical energy to power electronics or to produce light, heat, cooling, sound, motion/mechanical energy or other intended outcomes. Load can also refer to the cumulative electric energy consumed at any given point in time by a group of such devices or appliances.
Load Management	The process of adjusting or controlling a Customer's electrical Load to assist a utility in achieving a balance between its Customers' Demands and its electrical energy, as opposed to adjusting power station output to match the varying requirements of Customer Load. Also referred to as Demand Side Management (DSM).
Meter	The device(s) and any auxiliary equipment required to measure the Electric Service supplied by OPPD to a Customer at a Point of Delivery.
Owner	The person(s) having Ownership of the Premises or acting as an agent for the Owner.
Point of Delivery	The physical location at which OPPD supplies Electric Service to a Customer and which, unless otherwise agreed upon between OPPD and the Customer, shall be the point where OPPD's Service Wires are joined to the Customer's service terminals.
Power Factor	The ratio obtained by dividing the Customer's maximum kilowatt Demand by the Customer's maximum kilovolt-ampere Demand.
Premises	Building or tract of land identified in a deed stating the details of the conveyance of the property. For OPPD, the Premises details the location of building or tract of land at which Electric Service is supplied by OPPD.
Primary Generating Unit	A Customer-operated generating unit used to supply electrical Load within the Customer's facility, which operates in parallel to OPPD's system, and is not an Emergency Generating Unit.

Primary Service	Single-Phase or Three-phase service taken from OPPD's system at a standard available voltage above 11,000 volts, provided there is only one transformation involved from OPPD's transmission voltage (above 60,000 volts) to the service voltage.
Qualified Generator	Generators that qualify for net metering as set forth in the Nebraska Revised Statutes. Qualified Generators are interconnected, in accordance with an interconnection agreement, behind a Customer's service Meter located on the Customer's Premise with an aggregate nameplate capacity of 100 kW or less that uses as its energy source: methane, wind, solar, biomass, hydropower, or geothermal and is controlled by the generation owner.
Rate Schedule	Outlines the rate(s), fees, and charges for, or in connection with, Electric service received from OPPD.
Residential	House, trailer, apartment, flat or unit of a multi-family dwelling that is equipped with cooking facilities. Electric Service for one single-family dwelling may be served on a Residential Service Rate Schedule.
Rider Schedule	Outlines the rate(s), fees and charges used in conjunction with the Customer's electrical Rate Schedule. Rider Schedules can be optional or required based on Electric Service requirements.
Schedule	Rates, charges and other provisions under which service is supplied.
Seasonal Energy Efficiency Ratio (SEER)	The total cooling of a central air conditioner or heat pump in British thermal units (Btu) during its normal annual usage period for cooling divided by the total electric energy input in watthours during the same period as rated by the American Refrigeration Institute (ARI) Guide.
Secondary Service	Single-Phase or Three-Phase service taken from OPPD's system at a standard available voltage below 11,000 volts, provided the conditions defined under "Primary Service" are not applicable.
Service Area	The geographic area in which OPPD provides Electric Service.
Service Wires	The wires, owned by OPPD, connecting OPPD's distribution system to a Customer's service terminals.
Small Power Production	A facility with less than 80,000 kilowatts of installed capacity that produces electricity from such primary energy sources as biomass, waste, or renewable resources including wind, solar, geothermal, and hydroelectric energy.
Standby Service	Service to supply electrical energy to serve a Customer's Load that is usually served by the Customer's generating unit.

SERVICE REGULATIONS

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STARTING SERVICE

Application for Service

An applicant may make a written, verbal, or electronic application to OPPD for service(s) and will be required to provide the following information:

- Social security number, or
- Federal tax identification number

If the social security or federal tax identification numbers are unavailable, a birthdate in combination with verifiable, government-issued identification can be used.

OPPD may require proof of occupancy before application of service; additionally, the Customer may be required to pay a billed or unbilled debt, identified by OPPD as the applicant's responsibility, before the establishment of service.

OPPD relies upon the fact that the applicant is authorized to make the application, is acting in good faith, and is providing valid and accurate information. An applicant who fails to comply with this section may be denied service.

Upon application for service at a Premises, the Customer will be charged an activation fee. This fee will be included in the next monthly bill.

Account Security

OPPD may require the Customer to maintain a cash deposit or other form of account security acceptable to OPPD that is deemed adequate by OPPD to secure payment of an account or accounts for Electric Service and related services.

Application for Rate Schedules

The service supplied under the Rate and Rider Schedules is subject to the Service Regulations.

These Service Regulations shall apply to all services supplied by OPPD.

Residential Customers

The following Rate and Rider Schedules are subject to a Residential Customer's selection:

- Rate Schedule Nos. 115 and 120
- Rider Schedules Nos. 355, 483, and 500

When a Residential Customer applies for service, they must indicate the Rate Schedule for which they are applying. If a Residential Customer is eligible to take Electric Service from OPPD under Rate Schedule 115 or 120, the Customer is responsible for the selection of that Rate Schedule, and it will not be applied retroactively. Any new Rate Schedule will become effective after the next Meter reading cycle.

Customers taking Electric Service as single-phase alternating current will be supplied at OPPD's standard voltages of 240 volts or less when All-Electric Service furnished under this Rate Schedule is measured by one Meter unless otherwise specified in the Service Regulations. Not applicable to shared or resale service.

General Service Customers

The following Rate and Rider Schedules are subject to a General Service Customer's selection:

- Rate Schedules Nos. 261M
- Rider Schedules Nos. 355, 469, 469S, 483, 484, and 500

Customers taking Electric Service as single-phase or three-phase alternating current will be supplied at OPPD's standard voltages, for all uses, when all the Electric Services at one location are measured by one Meter, unless the Customer takes emergency or special service as required by OPPD's Service Regulations. Not applicable to shared or resale service.

~~After January 2027,~~ OPPD will annually evaluate the actual monthly Demand of the four (4) Summer billing months for all General Service Customers at the conclusion of the June through September period. Customers, if necessary, will be moved to the appropriate Rate Schedule prior to the start of next calendar year based on the results of that evaluation. OPPD will provide Customers who will be moved to a new Rate Schedule a minimum of 30 days notice prior the change.

The Applicability standards for General Service Customers are as follows:

~~For the 2026 calendar year, all Small General Service (Rate Schedules 226, 230 and 231) and Large General Service (Rate Schedules 232 and 245) Customers must remain on their Rate Schedule of record as of January 1, 2026. Effective January 2027 these Customers will be moved, if necessary, to the appropriate Rate Schedule based on following revised Applicability standards that will be implemented at that time:~~

Rate Schedule	Applicability
226	This Rate Schedule is applicable to Owners of farms, or renters with the Owner's guarantee in rural areas.
230	This Rate Schedule is applicable to all General Service Customers throughout OPPD's Service Area that record an average actual monthly Demand of less than or equal to 50 kilowatts during the four (4) Summer billing months, June through September.

231	This Rate Schedule is applicable to all General Service Customers throughout OPPD's Service Area that record an average actual monthly Demand of greater than 50 kilowatts and less than or equal to 3,000 kilowatts during the four (4) Summer billing months, June through September.
232	This Rate Schedule is applicable to all General Service Customers throughout OPPD's Service Area that record an average actual monthly Demand of greater than 3,000 kilowatts and less than or equal to 10,000 kilowatts during the four (4) Summer billing months, June through September.
245	This Rate Schedule is applicable to all General Service Customers throughout OPPD's Service Area that record an average actual monthly Demand of greater than 10,000 kilowatts during the four (4) Summer billing months, June through September.
~~250~~	~~Eliminated effective January 1, 2026~~

~~After January 2027, OPPD will annually evaluate the actual monthly Demand of the four (4) Summer billing months for all General Service Customers at the conclusion of the June through September period. Customers, if necessary, will be moved to the appropriate Rate Schedule prior to the start of next calendar year based on the results of that evaluation. OPPD will provide Customers who will be moved to a new Rate Schedule a minimum of 30 days notice prior the change.~~

SERVICE CONTRACT

OPPD will supply Electric Service to a Customer under the terms and conditions of the applicable Rate Schedule(s) and Service Regulations. OPPD, at its discretion, may also require an individual service contract for a Customer's Electric Service. By accepting Electric Service from OPPD, the Customer agrees to comply with OPPD's Rate Schedule(s) and Service Regulations.

Unlawful Use of Service

For diversion of service as defined in Nebraska statues, OPPD may pursue any or all civil or criminal statutory or common law remedies.

Tampering with, bypassing, altering, damaging, misusing or interfering with OPPD's Meter installation or its proper functioning will result in disconnection of service and prosecution under applicable laws. The Customer, at the applicable rate, will be liable for energy not recorded on the Meter, plus all expenses incurred by OPPD as a result of the unauthorized act(s).

Refusal of Service

OPPD may decline to service an applicant or Customer and disconnect services in certain situations such as:

- Failure to comply with these Service Regulations and/or with any applicable governmental regulations
- Installation is known to be hazardous or of such character that satisfactory service cannot be provided
- Refusal to meet account security requirements
- Presented fraudulent documentation or information to establish an account
- OPPD has discovered Meter tampering, theft or diversion of service
- The applicant has applied for service at a Premises where the previous Customer received service and is indebted to OPPD and:
    - The new application for service is made to assist the previous Customer evading or avoiding payment for the indebtedness or
    - The previous Customer no longer occupies the Premises, but the applicant is found to have occupied the Premises and benefitted from service prior to the date of application and has refused to pay charges incurred during such occupancy

CONDITIONS OF SERVICE

Easements and Legal Authority

The utility retains all rights granted under utility easements, which run with the property and permit access for the installation, maintenance, and operation of electric service equipment.

Right of Access

The District or its authorized agents shall have the right of unobstructed and safe access to the Customer's Premises, at all times the District determines access is necessary, for the purpose of reading meters, tree trimming, removing or exchanging District Property, and installing, inspecting, testing, disconnecting or repairing District equipment.

Customer Responsibility for Access

Customers, including landlords and property managers, are responsible for ensuring that:

- OPPD equipment, including Meters, are readily accessible to utility personnel
- Any gates, doors, or enclosures that restrict access are unlocked or utility personnel are provided with keys, codes, or other means of entry
- Pets or hazards that may impede safe access are properly managed

Failure to Provide Access

If access to OPPD equipment, including the Meter, is denied or obstructed:

- The utility may issue, and customers shall pay, estimated bills based on historical usage
- The customer will be notified and given a reasonable opportunity to correct the issue
- Continued failure to provide access may result in disconnection of service, the imposition of an access charge, or both, in accordance with applicable regulations and required notice

Tree Trimming

Customers shall permit OPPD to remove or trim trees and other vegetation, including the removal of limbs, to the extent that trimming is reasonably necessary to prevent interference with OPPD's transmission and distribution power lines and other electric equipment or to protect the safety of the Customer, the general public, or OPPD's property. Any trimming of trees and vegetation on the Customer's Premises that interfere with OPPD's Service Wires shall be the responsibility of the Customer and enforceable by OPPD as provided by law.

OPPD and Customer Roles and Responsibilities

OPPD will designate a point on the Customer's Premises where service will be delivered. Customer will provide and maintain adequate support and protection for attachment of OPPD's overhead or underground Service Wires on their Premises and will be responsible for any damages caused by the failure of or defect in such support or protection.

The Customer shall furnish if requested, suitable space on the Customer's Premises for OPPD's transformer equipment, as well as switching and capacitor equipment.

OPPD will furnish metering equipment required to measure the service supplied and will keep said equipment accurate within reasonable limits. The Customer will provide, without cost to OPPD, adequate space in a suitable location for OPPD's metering equipment.

Customer will secure all necessary permits for wiring on the Customer's Premises, will install such wiring in compliance with the National Electrical Code and all applicable laws, regulations, and ordinances, and will pay all inspection fees. OPPD will not be responsible for inspection of wiring on the Customer's Premises but reserves the right to require inspection before connecting service. OPPD may postpone the actual construction of its facilities to a Customer until Customer's wiring has been approved by the proper inspection authorities, has met OPPD's requirements, and is ready for connection to OPPD's system.

Unless otherwise agreed in writing, OPPD will retain title to all property installed or supplied by OPPD on a Customer's Premises and said property may be removed by OPPD at any time. The Customer will safeguard and provide adequate protection for OPPD's property (including poles, transformers and metering equipment) located on Customer's Premises and will maintain clear and safe access at all reasonable times. The Customer must keep the area around OPPD's equipment free of obstacles to facilitate OPPD operations and maintenance. This cleared area is to extend at least three (3) feet from each piece of equipment unless otherwise noted on the individual component.

Redundant Service

Customers taking Electric Service under any of OPPD's Rate Schedules will not receive redundant Electric Service at the Point of Delivery unless they are applicable and choose to take service under Rider Schedule No. 484 – Supplemental Distribution Capacity Rider.

Power Factor Equipment

OPPD reserves the right to measure the Customer's Power Factor. If the resulting measurement is less than the ratio specified in the Customer's applicable Rate Schedule, OPPD may require the Customer to provide facilities for OPPD to install kilovolt ampere metering. OPPD may increase the Customer's kilowatt Demand for billing purposes under the Customer's applicable Rate Schedule.

Customers with equipment or facilities having inherently low Power Factor characteristics should consider installing additional equipment to improve the Power Factor to avoid an increase in their bills and minimize losses on their electrical system.

Electrical Problems Caused by the Customer

The electricity usage or equipment operations of any Customer shall not cause electrical disturbances or problems for other Customers. Disturbances or problems include but are not limited to: steady-state voltage excursions beyond recognized limits (the latest revision of ANSI C84.1), transient disturbances, magnetic field interference, stray current/voltage, radio frequency interference, and Customer-Generated harmonics exceeding recognized limits (the latest revision of IEEE 519). It is the Customer's responsibility to take corrective action to comply with all applicable standards or pay the costs incurred by OPPD to take appropriate corrective action as a result of an electrical disturbance or problem. Failure, inability or refusal to remedy or rectify OPPD's concerns to conform to such limits, within a commercially reasonable amount of time, may result in disconnection of service.

OPPD Responsibility

OPPD will supply Electric Service consistent with prudent utility practice and will endeavor to provide, but does not guarantee, uninterrupted service and is not responsible for any loss or damages sustained by a Customer as a result of outages on the system, including but not limited to service disruptions that are caused, contributed to, or exacerbated by:

- Weather
- Repairs or maintenance
- Alterations
- Unavailability of supply
- Conditions of Customer's Premises are dangerous to persons, property, or service to others
- Nonpayment by the Customer for amounts due
- Customer's failure to provide means of access for obtaining regularly scheduled readings of the Meter or for testing OPPD's equipment
- Customer' failure to protect OPPD's equipment from theft, abuse, or vandalism
- OPPD's actions to prevent fraud or abuse of OPPD property
- Outages caused by third parties or animal interference

Customer waives claim for, and hereby releases and discharges OPPD from claims for, and shall indemnify and save harmless OPPD from, any and all loss and damage arising from an interruption of service, including loss or damage caused by the negligence of OPPD. Customer further waives claim for, and hereby releases and discharges OPPD from claims for, and shall indemnify and save harmless OPPD from, any and all loss and damage arising from or on account of injury to persons (including

death), or damage to property on the Premises of a Customer or under a Customer's control, unless such loss, damage, or injury is the natural, probable and reasonably foreseeable consequence of OPPD's negligence, and such negligence is the sole and proximate cause thereof.

Charge for Service

When a Customer applies for service which necessitates an extension of OPPD's electric facilities to serve the Customer, OPPD reserves the right to collect from the Customer, in advance, part or all of the cost of such extension when:

- The anticipated revenue to OPPD is not in proportion with the cost of such extension
- The extension is required because of abnormal operating characteristics of the equipment to be operated by the Customer
- The extension is required for emergency or special services
- The extension is not the least cost means of providing such services

A charge will occur for each temporary overhead or underground single-phase service connection, consisting of Service Wires and a Meter. When more than Service Wires and a Meter are required, the Customer will pay for the work done by OPPD on a contract basis.

Charge for Re-Establishing Service

The charge for service and the reconnection charge required by OPPD's Service Regulations will not apply to the re-establishment of service after the destruction of the Customer's Premises resulting from explosion, fire, flood or storm. In such cases, the equivalent service will be re-established at the Customer's option at a temporary or permanent location. If the damaged Premises are repaired within a reasonable time, not to exceed two years, the charges defined will not apply when the Customer moves back to the Customer's original location.

Transfer of Service

Contracts or service with OPPD will not be assignable or transferable by the Customer without the written consent of OPPD.

RESALE, REDISTRIBUTION, OR EXTENSION OF ELECTRIC SERVICE

The resale, redistribution or extension of Electric Service will not be allowed in OPPD's service territory except under conditions identified in these Service Regulations.

The redistribution of electricity by a Customer from electric vehicle charging, truck stop, campground, or other similar plug-in power equipment will not be considered the resale of electricity as long as the charge for the plug-in service is not sold on a metered kilowatt-hour or kilowatt basis. The Customer is not prohibited from recovering the cost of the electric vehicle charging equipment or plug-in power equipment and related infrastructure.

Except as otherwise expressly allowed by these service regulations, an Owner or Customer is prohibited from charging a tenant or occupant for Electric Service based on the tenant's or occupant's electrical usage on a per kilowatt-hour basis. Electric Service supplied by OPPD to an Owner or Customer may be redistributed by an Owner or Customer to a tenant or occupant

of the Owner's or Customer's Premises only when the amount the Owner or Customer charges the tenant or occupant for Electric Service is included as a part of the rent with no variation in the amount charged based on the actual amount of electricity used by the tenant or occupant. Otherwise, Electric Service must be supplied by OPPD directly to each tenant or occupant through OPPD's individual meters.

This regulation does not apply to municipalities purchasing wholesale energy under power contracts.

TRANSFER OF DEMAND

Historical actual Demand will remain in effect on accounts where a rate change has been executed. All aspects of the new rate will be applied using the historical actual Demand data. Historical actual Demand will remain in effect on accounts where a name change has been requested, and the Customer's tax identification number remains the same.

COMBINED RESIDENTIAL AND GENERAL SERVICE

A Customer in a single-family dwelling, parts of which are used for business purposes, may purchase service under a Residential Rate Schedule when the floor area of the part used for General Service purposes does not exceed 25% of the combined Residential and General Service floor area.

EXCEPTIONS TO "ALL SERVICE" REQUIREMENTS

Customers with a Rate Schedule that requires one Meter for all the Customer's services may maintain separate Meters in the following situations:

- When a Customer is required by law to provide separate wiring circuits for emergency lighting service, sprinklers or alarm systems, and this separate service cannot feasibly be metered with the remainder of the Customer's service
- When a Customer operates X-ray, welder or other equipment producing abnormal voltage fluctuations or other power quality issues, OPPD may require metering that equipment separately.
- When a Customer occupies two (2) or more spaces within the same building, where these spaces are separated by firewalls or intervening spaces, or are on different floors, and are not interconnected by private doors, passages, or stairways, separate Meters, as allowed by law, may be used for each space.

In each of the above cases, the separately metered special service shall be billed under an applicable Rate Schedule.

DISTRIBUTED ENERGY RESOURCE (DER) / DISTRIBUTED GENERATION (DG)

To ensure the safety of OPPD personnel and the public, and to protect the service of other Customers, a Customer who operates their own electric generating equipment and/or Energy Storage system is required to comply with all OPPD safety, metering, interconnection, and operation requirements. No connection will be made between generation and/or Energy Storage equipment and the service lines of OPPD without specific inspection and approval by OPPD. Any unapproved installation shall be grounds for immediate disconnection of OPPD's service.

OPPD will make its requirements for DER/DG compliance available upon request. OPPD requirements for compliant DER/DG interconnections are subject to change by OPPD.

Energy Storage systems can be applied and utilized by a Customer in a variety of ways. Depending upon how Energy Storage systems are installed and operated by a Customer, OPPD may interpret and consider Customer Energy Storage systems to be equivalent to generating units, or equivalent to other OPPD regulated equipment or activities, for all purposes in the application of OPPD Service Regulations. OPPD will also consider the operation of Energy Storage and the originating source of energy stored in determining Customer eligibility (or ineligibility) to participate in various OPPD rate programs.

Unless otherwise specified in the applicable Rate Schedule, the Customer will provide or reimburse OPPD for necessary grid or service modifications for the interconnection of generation or Energy Storage.

A Customer's failure to notify OPPD of the operations of units within the Customer's facility that meet the conditions of Rider Schedule No. 464 will result in:

- Application of the Excess Demand Charge as specified in Rider Schedule No. 464 to the combined nameplate rating of the units and,
- Retroactive billing of the Excess Demand Charge for the entire period such units were in operation.

METERING

Metering equipment must be located on the exterior of new and rewired construction. OPPD may grant exceptions under certain circumstances.

Location of Meters

Meters may be located:

- Externally on the structure (e.g., wall-mounted or pedestal-mounted)
- Internally within a residence or building
- Behind access barriers, such as fences, gates, locked enclosures, or other obstructions; provided, however, that authorized personnel obtain access

Separate Billing for Each Meter

When a Customer requests OPPD to supply service to their Premises at more than one Point of Delivery, the service measured by the Meter at each Point of Delivery will be considered a separate service, and Meter readings will not be combined for billing purposes.

When it is impractical, uneconomical, or undesirable to a Customer to accept the standard OPPD single Point of Delivery service, then at the option of OPPD, multiple service(s) may be allowed. The Customer is required to compensate OPPD for the additional construction cost.

Master Metering

Master metering is one Meter that measures consumption to more than one Premise

and meets each of the following criteria:

- The Customer is responsible for the installation and maintenance of all distribution equipment required to serve the facility on the Customer's side of the master Meter
- Premises must be owned by the same person or entity. If commercial or industrial, the business must operate as one integral unit under the same name
- Services must be "single building" or "adjacent buildings"
- Service must feed all buildings at the same voltage

A "single building," as used in this regulation, refers to a freestanding facility. Buildings that are connected by a walkway that includes space used for offices or other retail service facilities are considered a single building. Buildings connected by walkways for pedestrian traffic only are not considered part of a single building.
"Adjacent buildings," as used in this regulation, includes directly adjoining buildings or buildings directly across a street, alley or other public way, but does not include buildings separated from the Customer's places of business by intervening structures. The adjacent buildings must be used to carry on parts of the same commercial or industrial business, and the business must operate as one integral unit under the same name. All such service is to be used by the Customer and served through one Meter.

The Customer will also be billed on the appropriate General Service Rate Schedule.

Totalization of Meters

For Commercial and Industrial Customers who have multiple electrical Points of Delivery serving the Customer's facility, a Meter will be installed at each Point of Delivery. Totalizing across Meters to a Customer's facility to calculate the Customer's service costs will be allowed if the Customer's service design meets the following criteria:

- Customers requesting the totalizing of their Loads at multiple Points of Delivery must have the same Federal Tax ID #
- Service must be three-phase
- Service must serve building(s) at the same voltage
- Service must be a single building, or buildings that are directly next to each other on the same side of the street, with no other structures between them.

"Totalized" metering, as used in this regulation, involves the interconnection of all Customer Point-of-Delivery Meters through wiring, electronic communication, or merging of Meter readings in software to effectively create one metering system and one combined Customer account for billing purposes. The resulting metering system would read consumption, simultaneous peak Demand, and other characteristics for all Points of Delivery as a combined whole.

Customers who totalize their Load will be required to pay for the installed costs of the second service. For additional information regarding the totalization of individual Meters, please contact OPPD's Customer Service Department.

Unmetered Service

Unmetered service is supplied only under the Rate Schedules providing municipal service for street lighting, traffic signals and signs, and private outdoor lighting.

Exceptions:

- *Emergency Sirens*: At OPPD's discretion, unmetered service may be supplied to governmental agencies for emergency sirens. The Customer will be billed monthly for the minimum charge under the applicable General Service Rate Schedules.

- *Other*: At OPPD's discretion, where the installation of metering equipment is impractical or uneconomical, and with the agreement of the Customer, unmetered service may be provided to Customers with fixed, permanently installed Loads. The monthly bills will be computed based on estimated kilowatt-hour use.

BILLING

Billing and Meter Reading

OPPD will normally read the Customer's Meter monthly. Bills will be generated using the applicable Rate Schedule at approximately one-month intervals based on the actual or estimated Meter reading. For all Customer's, the monthly billing period will usually be between 25 and 35 days. First and final bills for a service location or bills with less than 25 days or greater than 35 days will be prorated to reflect the number of days in that billing period.

When OPPD does not read the Meter, OPPD will issue an estimated bill. The Customer may be contacted to arrange a time for OPPD to read their Meter if there have been three (3) consecutive months of estimated Meter readings. All Meters will be read at least once every twelve (12) months.

Taxes

OPPD is required to collect and remit sales tax per applicable law. The total of all charges for service under the Rate Schedules will include applicable existing state and municipal taxes, any new or additional taxes, or increases in the rates of existing taxes.

Billing Terms and Conditions

The Customer's bill payment must be received on or before the due date designated on the bill or a late payment charge will be assessed. The late payment charge will be calculated as 4% of the billing components and any applicable taxes. Failure to receive a bill does not entitle the Customer to have the late payment charge waived. If a Customer's account becomes delinquent, the Customer is subject to OPPD's disconnection of service process, based on Nebraska Revised Statute 70-1605 or its successor, and all applicable fees; outlined in Rate Schedule No. 470 – General – Customer Service Charges.

OPPD has the right to transfer any delinquent bill balance to any other Premises or OPPD account for which the Customer is or becomes responsible in any manner, or any other Premises or OPPD account at or from which the Customer receives Electric Service. If a balance due for service at any previous address of a Customer is not paid within 15 days after ending service at such address, the balance will become delinquent, and service at the current address covered by the account may be

disconnected.

Service disconnected for delinquency will not be reconnected until all delinquent charges are paid or, at the discretion of OPPD, acceptable payment or account security arrangements are made.

Customer Disconnect and Reconnect at a given Premises within a 12-Month Period

In the event a Customer's service has been disconnected and has been reconnected within twelve (12) months of the service termination, the Customer will be charged the minimum monthly charge for the preceding twelve (12) months, or any part thereof.

Owner/Landlord Responsibilities

From the date of property acquisition, the Owner assumes responsibility for all Electrical Service usage at the premises, unless such service is actively billed directly to a tenant. The Owner will be responsible for interim service and associated charges at Premises when the Owner fails to disconnect utility service between tenancies. OPPD will bill the Owner for any unbilled usage. If the Owner wants the Electric Service disconnected automatically in the event an occupant or tenant terminates the Electric Service, the Owner must complete a Service Disconnection Form or a Landlord Contract Form and file it with OPPD.

Billing and Payment Options

Payment Options: Please see OPPD.com for billing and payment options. OPPD will accept bank card payments for several Rate Schedules. OPPD will not accept bank card payments for Customers on General Service Rate Schedules other than No. 226 and 230.

Level Payment: OPPD's Level Payment Plan will be made available to Customers receiving service on Rate Schedules Nos. 110, 115, 120, 230 and 231 who have an acceptable payment history with the OPPD. The Customer must comply with the conditions of the regular Rate Schedule and any applicable rate riders. Customers served under Rate Schedules Nos. 230 and 231 are required to be an OPPD Customer for at least one year to qualify.

OPPD does not pay interest on Level Payment Plan accounts with credit balances. For Customers on OPPD's Level Payment Plan, the Late Payment Charge will be calculated as 4% of the current month's level payment amount.

Determination of Billing Non-Demand or Demand

OPPD will utilize information provided by the Customer or obtained from the Customer's usage history or Meter to determine whether a Customer will be billed on a non-Demand or a Demand Rate Schedule. If Demand history is available for Customers moving from a non-Demand Rate Schedule to a Demand Rate Schedule, this Demand history will be used in determining the Customer's Billing Demand for future billing periods. If the Customer provides to OPPD, in writing, information that shows permanent changes in the type of electrical service required, at OPPD's discretion, the Customer may be moved to a non-Demand Rate Schedule for future billings.

Billing Adjustments

OPPD makes reasonable efforts to bill all utility accounts accurately. If errors occur, the error may result in over- or under-billing a Customer's account. Upon discovery of such an error, OPPD will begin the process of either billing the Customer for undercharges or crediting the Customer's account for overcharges, without interest. OPPD will back-bill a Customer or credit a Customer's account for no more than a four-year period.

OPPD will not adjust inaccurate Customer billing resulting from mislabeled Meter sockets or cross-wiring to a service within the building's electrical system. At OPPD's discretion, administrative costs associated with mislabeled Meter sockets or cross-wiring to a service may be charged to the Premises Owner.

RATE SCHEDULES

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RATE SCHEDULE NO. 110

Standard Residential Service

APPLICABILITY

This Rate Schedule is applicable to all Customers throughout OPPD's Service Area who meet the criteria to be a Residential Customer as defined in the Service Regulations.

BILLING COMPONENTS

Monthly Service Charge: $30.00 per month

Energy Charge:

Energy Usage	Summer (June 1 – Sept. 30)	Non-Summer (Oct. 1 – May 31)
Per kWh	12.909~~11.937~~ cents/kWh	9.879~~9.503~~ cents/kWh

Rider Schedule No. 461 – Fuel and Purchased Power Adjustment applies to this Rate Schedule.

Minimum Monthly Bill: $30.00

The minimum monthly bill is the monthly service charge. Any energy usage by the Customer during a billing period is charged in addition to the minimum bill.

Late Payment Charge:

A Late Payment Charge in the amount of 4% of the Billing Components and applicable taxes will be assessed if the current month's bill payment is not received by OPPD on or before the due date. For Customers on OPPD's Level Payment Plan, the Late Payment Charge will be calculated as 4% of the current level payment amount.

ADMINISTRATIVE

Service Regulations

Customers under this Rate Schedule must comply with all OPPD Service Regulations.

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RATE SCHEDULE NO. 115

Residential Conservation Service

APPLICABILITY

This Rate Schedule is applicable to all Customers throughout OPPD's Service Area who meet the criteria to be a Residential Customer as defined in the Service Regulations. To qualify for this Rate Schedule, the Customer must meet each of the following:

- Have an electric heat pump in operation that has a Seasonal Energy Efficiency Rating of 14 or higher, with the heat pump installation passing OPPD's size and efficiency tests, and
- Supply at least 50% of the space-conditioning requirements using the electric heat pump.

BILLING COMPONENTS

Monthly Service Charge: $30.00 per month plus,

Energy Charge:

Energy Usage	Summer (June 1 – Sept. 30)	Non-Summer (Oct. 1 – May 31)
Per kWh	10.788~~10.189~~ cents/kWh	9.277~~8.738~~ cents/kWh

Rider Schedule No. 461 – Fuel and Purchased Power Adjustment applies to this Rate Schedule.

Minimum Monthly Bill: $30.00

The minimum monthly bill is the monthly service charge. Any energy usage by the Customer during a billing period is charged in addition to the minimum bill.

Late Payment Charge:

A Late Payment Charge in the amount of 4% of the Billing Components and applicable taxes will be assessed if the current month's bill payment is not received by OPPD on or before the due date. For Customers on OPPD's Level Payment Plan, the Late Payment Charge will be calculated as 4% of the current level payment amount.

ADMINISTRATIVE

Schedule Period

This Rate Schedule will be available for a minimum of five (5) years. Availability beyond five (5) years will continue until the termination of the heat pump program and the last Customer to qualify for this Rate Schedule completes the minimum five (5) year availability.

Service Regulations

Customers under this Rate Schedule must comply with all OPPD Service Regulations.

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RATE SCHEDULE NO. 120

~~(Effective 1/1/2027)~~

Standard Residential Service – TOU Pilot

APPLICABILITY

This Rate Schedule is available to all Customers who currently take service under Rate Schedule NO. 110 and who had an Advanced Meter Infrastructure smart meter installed by OPPD at their premises as of June 1, 2026.

BILLING COMPONENTS

Monthly Service Charge: $30.00 per month

Energy Charge Per kWh:

Summer (June 1 – Sept. 30) On-Peak	~~_____~~35.221 cents/kWh
Summer (June 1 – Sept. 30) Off-Peak	~~_____~~8.805 cents/kWh
Non-Summer (Oct. 1 – May 31)	~~_____~~9.879 cents/kWh

Rider Schedule No. 461 – Fuel and Purchased Power Adjustment applies to this Rate Schedule.

Minimum Monthly Bill: $30.00

The minimum monthly bill is the monthly service charge. Any energy usage by the Customer during a billing period is charged in addition to the minimum bill.

Late Payment Charge:

A Late Payment Charge in the amount of 4% of the Billing Components and applicable taxes will be assessed if the current month's bill payment is not received by OPPD on or before the due date. For Customers on OPPD's Level Payment Plan, the Late Payment Charge will be calculated as 4% of the current level payment amount.

ADMINISTRATIVE

Definitions

Summer On-Peak: The hours between 3:00 PM and 7:00 PM, Monday through Friday, from June 1 to September 30, excluding Federal Holidays.

Summer Off-Peak: All hours from June 1 to September 30 outside of those established in the Summer On-Peak period definition.

Special Conditions

OPPD reserves the right to limit total participation on this Rate Schedule.

Service Regulations

Customers under this Rate Schedule must comply with all OPPD Service Regulations.

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RATE SCHEDULE NO. 226

Irrigation Service

APPLICABILITY

This Rate Schedule is applicable to Owners of farms, or renters with the Owner's guarantee, in rural areas.

OPPD reserves the right to collect from the Customer in advance, part or all of the cost of the additional investment if OPPD's estimated additional investment in lines, transformers, Meter and accessory equipment to serve a pumping location exceeds $75.00 per horsepower of connected Load for single-phase service or $105.00 per horsepower for three-phase service.

BILLING COMPONENTS

Annual Connected Load Charge:

Annual Charge	Single-Phase	Three-Phase
Per horsepower (HP)	$26.48~~23.32~~	$29.44

Energy Charge:

Energy Usage	Single-Phase	Three-Phase
Per kWh	11.07 cents/kWh	11.07 cents/kWh

Rider Schedule No. 461 – Fuel and Purchased Power Adjustment applies to this Rate Schedule.

Minimum Annual Connected Load Charge:

$264.80~~233.20~~ for Single-Phase
$294.40 for Three-Phase

Minimum Annual Connected Load Charge is calculated as the 10 HP minimum Annual Connected Load Charge requirement.

Late Payment Charge:

A Late Payment Charge in the amount of 4% of the Billing Components and applicable taxes will be assessed if the current month's bill payment is not received by OPPD on or before the due date.

Billing Procedure

The annual billing period for Rate Schedule No. 226 – Irrigation Service, begins in May and ends the following April. Customers will be billed one-third of the annual connected load charge during May, June, and July of each of the contract years, plus any charges for energy. During the remaining months, the Customer will be billed for the energy used each month. If a Customer starts service before or after May 1st, the prorated connected load charge will be billed in May, June, or July depending on the start date for the Customer. When a Customer discontinues service, the prorated connected load charge will be billed or credited the following month.

ADMINISTRATIVE

Definitions

Connected Load: The total full Load continuous ratings in horsepower, as prescribed by the standards of the National Electrical Manufacturers Association in effect at the time of purchase from the manufacturer of motors and other current-consuming equipment, installed by the Customer.

Equivalent Electrical Load: The electrical power required to operate mechanical Load at the nameplate horsepower. One horsepower will be converted to an equivalent electrical Load using an 85% efficiency. (One horsepower mechanical equals 877 watts electrical.)

Contract Period

Five years, or longer, at OPPD's discretion. Each contract, at the expiration date, will automatically be renewed for an additional one-year period, unless cancelled by written notice by either party at least 60 days before the expiration date.

Service Regulations

Customers under this Rate Schedule must comply with all OPPD Service Regulations.

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RATE SCHEDULE NO. 230

General Service Non-Demand

APPLICABILITY

This Rate Schedule is applicable to all Customers throughout OPPD's Service Area that have monthly Billing Demands less than 50 kilowatts during each of the four (4) Summer billing months, June through September.

Customers taking Electric Service as single phase or three phase alternating current will be supplied at OPPD's standard voltages, for all uses, when all the Electric Services at one location are measured by one Meter, unless the Customer takes emergency or special service as required by OPPD's Service Regulations. Not applicable to shared or resale service.

This Rate Schedule is not available to those Customers taking service under Rate Schedule No. 226 – Irrigation Service.

BILLING COMPONENTS

Monthly Service Charge: $33.00 per month

Energy Charge:

Energy Usage Per kWh	Summer (June 1 – Sept. 30)	Non-Summer (Oct. 1 – May 31)
	11.116 cents/kWh	8.717 cents/kWh

Minimum Monthly Bill: $33.00

The minimum monthly bill is the monthly service charge. Any energy used by the Customer during a billing period is charged in addition to the minimum bill.

Late Payment Charge:

A Late Payment Charge in the amount of 4% of the Billing Components and applicable taxes will be assessed if the current month's bill payment is not received by OPPD on or before the due date. For Customers on OPPD's Level Payment Plan, the Late Payment Charge will be calculated as 4% of the current level payment amount.

ADMINISTRATIVE

Service Regulations

Customers under this Rate Schedule must comply with all OPPD Service Regulations.

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RATE SCHEDULE NO. 230
~~(Effective 1/1/2027)~~

General Service Non-Demand

APPLICABILITY

General Service Customers that record an average actual monthly Demand of less than or equal to 50 kilowatts during the four (4) Summer billing months, June through September, shall take service under this Rate Schedule.

This Rate Schedule is not available to those Customers taking service under Rate Schedule No. 226 – Irrigation Service.

BILLING COMPONENTS

Monthly Service Charge: $33.00 per month

Energy Charge:

Energy Usage	Summer (June 1 – Sept. 30)	Non-Summer (Oct. 1 – May 31)
Per kWh	12.329 cents/kWh	9.271 cents/kWh

Rider Schedule No. 461 – Fuel and Purchased Power Adjustment applies to this Rate Schedule.

Minimum Monthly Bill: $33.00

The minimum monthly bill is the monthly service charge. Any energy used by the Customer during a billing period is charged in addition to the minimum bill.

Late Payment Charge:

A Late Payment Charge in the amount of 4% of the Billing Components and applicable taxes will be assessed if the current month's bill payment is not received by OPPD on or before the due date. For Customers on OPPD's Level Payment Plan, the Late Payment Charge will be calculated as 4% of the current level payment amount.

ADMINISTRATIVE

Service Regulations

Customers under this Rate Schedule must comply with all OPPD Service Regulations.

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RATE SCHEDULE NO. 231

General Service – Small Demand

APPLICABILITY

This Rate Schedule is applicable to all non-Residential Customers throughout OPPD's Service Area that meet or exceed a Billing Demand of 50 kilowatts during one of the four (4) Summer billing months, June through September.

Customers taking Electric Service as single-phase or three-phase alternating current will be supplied at OPPD's standard voltages, for all uses, when all Electric Service at one location is measured by one Demand Meter, unless the Customer takes emergency or special service as required by OPPD's Service Regulations. Not applicable to shared or resale service.

This Rate Schedule is not available to those Customers taking service under Rate Schedule No. 226 – Irrigation Service.

BILLING COMPONENTS

Monthly Service Charge: $19.86 per month

Demand Charge:

Billing Demand	Per kW Month
Per kW	$8.62

Minimum Billing Demand of 18 kW per month.

Energy Charge:

Energy Usage	Summer (June 1 – Sept. 30)	Non-Summer (Oct. 1 – May 31)
Per kWh	6.997 cents/kWh	5.669 cents/kWh

Rider Schedule No. 461 – Fuel and Purchased Power Adjustment applies to this Rate Schedule.

Minimum Monthly Bill: $175.02

The minimum monthly bill is calculated as the 18 kilowatt minimum Demand requirements of $155.16, plus the monthly service charge of $19.86. Any energy used by the Customer during a billing period is charged in addition to the minimum bill.

Late Payment Charge:

A Late Payment Charge in the amount of 4% of the Billing Components and applicable taxes

will be assessed if the current month's bill payment is not received by OPPD on or before the due date. For Customers on OPPD's Level Payment Plan, the Late Payment Charge will be calculated as 4% of the current level payment amount.

Determination of Demand

Demand, for any billing period, will be the kilowatts computed from the readings of OPPD's Meter for the 15-minute interval of the Customer's highest use during the same billing period.

If the Demand is less than 85% of the Customer's highest 15-minute kilovolt-ampere Demand, the kilowatt Demand will be increased under this Schedule by 50% of the difference between 85% of the kilovolt-ampere Demand and the Demand as determined above.

The Customer's Demand must be equal to or greater than the larger of the following:

- 85% of the highest 15-minute Power Factor-adjusted Demand during the Summer billing months of the preceding eleven (11) months, or
- 60% for the highest 15-minute Power Factor-adjusted Demand during the Non-Summer billing months of the preceding eleven (11) months, or
- 18 kilowatts

ADMINISTRATIVE

Service Regulations

Customers under this Rate Schedule must comply with all OPPD Service Regulations.

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RATE SCHEDULE NO. 231

~~(Effective 1/1/2027)~~

General Service – Small Demand

APPLICABILITY

General Service Customers that record an average actual monthly Demand of greater than 50 kilowatts and less than or equal to 3,000 kilowatts during the four (4) Summer billing months, June through September, shall take service under this Rate Schedule.

This Rate Schedule is not available to those Customers taking service under Rate Schedule No. 226 – Irrigation Service.

BILLING COMPONENTS

Monthly Service Charge: $19.86 per month

Demand Charge:

Billing Demand	Per kW Month
Per kW	$9.84

Minimum Billing Demand of 42 kW per month.

Energy Charge:

Energy Usage	Summer (June 1 – Sept. 30)	Non-Summer (Oct. 1 – May 31)
Per kWh	7.757 cents/kWh	5.820 cents/kWh

Rider Schedule No. 461 – Fuel and Purchased Power Adjustment applies to this Rate Schedule.

Minimum Monthly Bill: $433.14

The minimum monthly bill is calculated as the 42-kilowatt minimum Demand requirements of $413.28, plus the monthly service charge of $19.86. Any energy used by the Customer during a billing period is charged in addition to the minimum bill.

Late Payment Charge:

A Late Payment Charge in the amount of 4% of the Billing Components and applicable taxes will be assessed if the current month's bill payment is not received by OPPD on or before the due date. For Customers on OPPD's Level Payment Plan, the Late Payment Charge will be calculated as 4% of the current level payment amount.

Determination of Demand

Demand, for any billing period, will be the kilowatts computed from the readings of OPPD's Meter for the 15-minute interval of the Customer's highest use during the same billing period.

If the Demand is less than 85% of the Customer's highest 15-minute kilovolt-ampere Demand, the kilowatt Demand will be increased under this Schedule by 50% of the difference between 85% of the kilovolt-ampere Demand and the Demand as determined above.

The Customer's Demand must be equal to or greater than the larger of the following:

- 85% of the highest 15-minute Power Factor-adjusted Demand during the Summer billing months of the preceding eleven (11) months, or
- 60% for the highest 15-minute Power Factor-adjusted Demand during the Non-Summer billing months of the preceding eleven (11) months, or
- 42 kilowatts

ADMINISTRATIVE

Service Regulations

Customers under this Rate Schedule must comply with all OPPD Service Regulations.

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RATE SCHEDULE NO. 232

General Service – Large Demand

APPLICABILITY

This Rate Schedule is applicable to all non-Residential Customers throughout OPPD's Service Area.

Customers taking Electric Service as single phase or three phase alternating current will be supplied at OPPD's standard voltages, for all uses, when all the Electric Services at one location are measured by one Demand Meter, unless the Customer takes emergency or special service as required by OPPD's Service Regulations. Not applicable to shared or resale service.

BILLING COMPONENTS

Monthly Service Charge: $115.31 per month plus,

Demand Charge:

Billing Demand	Per kW Month
Per kW	$15.95

Minimum Billing Demand of 1,000 kW per month.

Energy Charge:

Energy Usage	All Months (Jan. 1 – Dec.31)
kWh	4.83 cents/kWh

Rider Schedule No. 461 – Fuel and Purchased Power Adjustment applies to this Rate Schedule.

Minimum Monthly Bill: $16,065.31

The minimum monthly bill is calculated as the 1,000 kilowatt minimum Demand requirements of $15,950, plus the monthly service charge of $115.31. Any energy used by the Customer during a billing period is charged in addition to the minimum bill.

Late Payment Charge:

A Late Payment Charge in the amount of 4% of the Billing Components and applicable taxes will be assessed if the current month's bill payment is not received by OPPD on or before the due date.

Determination of Demand

Demand, for any billing period, will be the kilowatts computed from the readings of OPPD's Meter for the 15-minute interval of the Customer's highest use during the same billing period.

If the Demand is less than 85% of the Customer's highest 15-minute kilovolt-ampere Demand, the kilowatt Demand will be increased under this Schedule by 50% of the difference between 85% of the kilovolt-ampere Demand and the Demand as determined above.

The Customer's Demand must be equal to or greater than the larger of the following:

- 85% of the highest 15-minute Power Factor-adjusted Demand during the Summer billing months of the preceding eleven (11) months, or
- 60% for the highest 15-minute Power Factor-adjusted Demand during the Non-Summer billing months of the preceding eleven (11) months, or
- 1,000 kilowatts

ADMINISTRATIVE

Service Regulations

Customers under this Rate Schedule must comply with all OPPD Service Regulations.

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RATE SCHEDULE NO. 232

~~(Effective 1/1/2027)~~

General Service – Large Demand

APPLICABILITY

General Service Customers that record an average actual monthly Demand of greater than 3,000 kilowatts and less than or equal to 10,000 kilowatts during the four (4) Summer billing months, June through September, shall take service under this Rate Schedule.

BILLING COMPONENTS

Monthly Service Charge: $115.31 per month plus,

Demand Charge:

Billing Demand	Per kW Month
Per kW	$17.84

Minimum Billing Demand of 2,550 kW per month.

Energy Charge:

Energy Usage	All Months (Jan. 1 – Dec.31)
kWh	5.208 cents/kWh

Rider Schedule No. 461 – Fuel and Purchased Power Adjustment applies to this Rate Schedule.

Minimum Monthly Bill: $45,607.31

The minimum monthly bill is calculated as the 2,550-kilowatt minimum Demand requirements of $45,492, plus the monthly service charge of $115.31. Any energy used by the Customer during a billing period is charged in addition to the minimum bill.

Late Payment Charge:

A Late Payment Charge in the amount of 4% of the Billing Components and applicable taxes will be assessed if the current month's bill payment is not received by OPPD on or before the due date.

Determination of Demand

Demand, for any billing period, will be the kilowatts computed from the readings of OPPD's Meter for the 15-minute interval of the Customer's highest use during the same billing period.

If the Demand is less than 85% of the Customer's highest 15-minute kilovolt-ampere Demand, the kilowatt Demand will be increased under this Schedule by 50% of the difference between 85% of the kilovolt-ampere Demand and the Demand as determined above.

The Customer's Demand must be equal to or greater than the larger of the following:

- 85% of the highest 15-minute Power Factor-adjusted Demand during the Summer billing months of the preceding eleven (11) months, or
- 60% for the highest 15-minute Power Factor-adjusted Demand during the Non-Summer billing months of the preceding eleven (11) months, or
- 2,550 kilowatts

ADMINISTRATIVE

Service Regulations

Customers under this Rate Schedule must comply with all OPPD Service Regulations.

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~~RATE SCHEDULE NO. 245~~

~~Large Power~~

~~APPLICABILITY~~

~~This Rate Schedule is applicable to all non-Residential Customers throughout OPPD's Service Area.~~

~~Customers taking Electric Service as three-phase alternating current will be supplied at an OPPD standard voltage above 11,000 volts provided there is only one transformation involved from an OPPD transmission voltage (above 60,000 volts) to the service voltage. Also, all the Electric Services at one location are measured by one Demand Meter, unless the Customer takes emergency or special service as required by OPPD's Service Regulations. Not applicable to shared or resale service.~~

~~BILLING COMPONENTS~~

~~Monthly Service Charge: $465.28 per month plus,~~

~~Demand Charge:~~

~~Billing Demand~~	~~Per kW Month~~
~~Per kW~~	~~$17.99~~

~~Minimum Billing Demand of 10,000 kW per month.~~

~~Energy Charge:~~

~~Energy Usage~~	~~All Months (Jan. 1 – Dec.31)~~
~~kWh~~	~~4.496 cents/kWh~~

~~Rider Schedule No. 461 – Fuel and Purchased Power Adjustment applies to this Rate Schedule.~~

~~Rider Schedule No. 462 – Primary Service Discount does not apply to this Rate Schedule.~~

~~Minimum Monthly Bill: $180,365.28~~

~~The minimum monthly bill is calculated as the 10,000 kilowatt minimum Demand requirements of $179,900 plus the monthly service charge of $465.28. Any energy used by the Customer during a billing period is charged in addition to the minimum bill.~~

~~Late Payment Charge:~~

~~A Late Payment Charge in the amount of 4% of the Billing Components and applicable taxes will be assessed if the current month's bill payment is not received by OPPD on or before the due date.~~

~~Determination of Demand~~

~~Demand, for any billing period, will be the kilowatts computed from the readings of OPPD's Meter for the 15-minute interval of the Customer's highest use during the same billing period.~~

If the Demand is less than 85% of the Customer's highest 15-minute kilovolt-ampere Demand, the kilowatt Demand will be increased under this Schedule by 50% of the difference between 85% of the kilovolt-ampere Demand and the Demand as determined above.

The Customer's Demand must be equal to or greater than the larger of the following:

- 85% of the highest 15-minute Power Factor-adjusted Demand during the Summer billing months of the preceding eleven (11) months, or
- 60% for the highest 15-minute Power Factor-adjusted Demand during the Non-Summer billing months of the preceding eleven (11) months, or
- 10,000 kilowatts

ADMINISTRATIVE

Service Regulations

Customers under this Rate Schedule must comply with all OPPD Service Regulations.

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RATE SCHEDULE NO. 245

~~(Effective 1/1/2027)~~

Large Power

APPLICABILITY

General Service Customers that record an average actual monthly Demand of greater than 10,000 kilowatts during the four (4) Summer billing months, June through September, shall take service under this Rate Schedule.

Customers taking Electric Service as three-phase alternating current will be supplied at an OPPD standard voltage above 11,000 volts provided there is only one transformation involved from an OPPD transmission voltage (above 60,000 volts) to the service voltage. Also, all the Electric Services at one location are measured by one Demand Meter, unless the Customer takes emergency or special service as required by OPPD's Service Regulations. Not applicable to shared or resale service.

BILLING COMPONENTS

Monthly Service Charge: $465.28~~—~~ per month plus,

Demand Charge:

Billing Demand	Per kW Month
Per kW	$20.11~~—~~

Minimum Billing Demand of 8,500 kW per month.

Energy Charge:

Energy Usage	All Months (Jan. 1 – Dec.31)
kWh	4.857~~—~~ cents/kWh

Rider Schedule No. 461 – Fuel and Purchased Power Adjustment applies to this Rate Schedule.

Rider Schedule No. 462 – Primary Service Discount does not apply to this Rate Schedule.

Minimum Monthly Bill: $171,400.28~~—~~

The minimum monthly bill is calculated as the 8,500-kilowatt minimum Demand requirements of $170,935~~—~~ plus the monthly service charge of $465.28~~—~~. Any energy used by the Customer during a billing period is charged in addition to the minimum bill.

Late Payment Charge:

A Late Payment Charge in the amount of 4% of the Billing Components and applicable taxes will be assessed if the current month's bill payment is not received by OPPD on or before the due date.

Determination of Demand

Demand, for any billing period, will be the kilowatts computed from the readings of OPPD's Meter for the 15-minute interval of the Customer's highest use during the same billing period.

If the Demand is less than 85% of the Customer's highest 15-minute kilovolt-ampere Demand, the kilowatt Demand will be increased under this Schedule by 50% of the difference between 85% of the kilovolt-ampere Demand and the Demand as determined above.

The Customer's Demand must be equal to or greater than the larger of the following:

- 85% of the highest 15-minute Power Factor-adjusted Demand during the Summer billing months of the preceding eleven (11) months, or
- 60% for the highest 15-minute Power Factor-adjusted Demand during the Non-Summer billing months of the preceding eleven (11) months, or
- 8,500 kilowatts

ADMINISTRATIVE

Service Regulations

Customers under this Rate Schedule must comply with all OPPD Service Regulation

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RATE SCHEDULE NO. 261M

Large Power – High-Voltage Transmission Level – Market Energy

APPLICABILITY

This Rate Schedule is applicable to all non-Residential Customers throughout OPPD's Service Area.

Customers taking Electric Service as three-phase service will be supplied radially from OPPD's system at a nominal standard voltage of 161,000 volts or 345,000 volts, where the Customer owns its electric substation for the delivery of the service.

The minimum Demand for service under this Rate Schedule is 20,000 kilowatts for service at 161,000 volts or a minimum Demand of 200,000 kilowatts for service at 345,000 volts each month.

Customers must substantiate to OPPD's satisfaction that their Demand requirements will meet the minimum Demand requirements of this Rate Schedule within 18 months of establishing service under this Rate Schedule.

The Customer's high voltage Electric Service will be measured by one Demand Meter, unless a Customer takes emergency or special service as required by OPPD's Service Regulations.

BILLING COMPONENTS

Monthly Service Charge: $10,000.00 per month plus,

Demand Charge:

Billing Demand	Per kW Month
Per kW	$29.55~~23.91~~

Minimum Billing Demand of 20,000 kilowatts per month for interconnection at 161,000 volts or 200,000 kilowatts per month for interconnection at 345,000 volts.

Energy Charge

An Energy Charge will be assessed based on the number of kilowatt-hours consumed in any given hour multiplied by the appropriate cost to purchase energy from the Southwest Power Pool (SPP) for that hour. OPPD will notify the Customer of the SPP node used to price the hourly energy and all applicable SPP charges. The billing notice will be enforceable under this Rate Schedule and OPPD's Service Regulations.

Rider Schedule No. 462 – Primary Service Discount does not apply to this Rate Schedule.

Minimum Monthly Bill:

$601,000~~488,200~~ for Customers taking service at 161,000 volts

or

$5,920,000~~4,792,000~~ for Customers taking service at 345,000 volts

The minimum monthly bill is calculated as the 20,000-kilowatt minimum Demand requirement of $591,000~~478,200~~ for interconnection at 161,000 volts, or 200,000 kilowatt minimum Demand requirement of $5,910,000~~4,782,000~~ for interconnection at 345,000 volts, plus the monthly service charge of $10,000. Any energy used by the Customer during a billing period is charged in addition to the minimum bill.

Late Payment Charge:

A Late Payment Charge in the amount of 4% of the Billing Components and applicable taxes will be assessed if the current month's bill payment is not received by OPPD on or before the due date.

Gross Revenue Charge:

The Charges under this rate shall be subject to the 5% Gross Revenue Charge to recover the payment in lieu of taxes as established in Neb, Const. art. VIII, sec. 11 OPPD will submit this payment to the appropriate political subdivision(s) as provided by the law.

Determination of Demand

Demand, for any billing period during the initial 18 months of service, will be the kilowatts computed from the readings of OPPD's Meter for the 15-minute interval of the Customer's greatest use during the same billing period.

For billing periods of 18 months or after the initial service date, Demand will be the kilowatts computed from the readings of OPPD's Meter for the 15-minute interval of Customer's highest use during the same billing period.

If, after month 17 of the initial service date, the Demand is less than 95% leading or lagging of the Customer's highest 15-minute kilovolt ampere Demand, the kilowatt Demand will be increased under this Schedule by 50% of the difference between 95% of the kilovolt ampere Demand and the Demand as determined above.

The Customer's Demand must be equal to or greater than the larger of the following:

- 90% of the highest 15-minute Power Factor-adjusted Demand during the Summer billing months of the preceding eleven (11) months, or
- 75% of the highest 15-minute Power Factor-adjusted Demand during the Non-Summer billing months of the preceding eleven (11) months, or
- 20,000 kilowatts for Customers receiving service at 161,000 volts, or
- 200,000 kilowatts for Customers receiving service at 345,000 volts

ADMINISTRATIVE

Special Conditions

Customers taking service under this Rate Schedule will be required to execute and comply with operational policies and any other requirements as determined by OPPD.

OPPD assumes no liability for Customer-Owned facilities.

OPPD will determine the Point(s) of Delivery using the information provided by the Customer regarding the Customer's requirements. The Point of Delivery will be based on the needs and requirements of OPPD's systems and facilities.

Due to the nature of service provided under this Rate Schedule, OPPD and the Customer will jointly agree upon a metering point that adequately and safely meets OPPD's requirements. If OPPD determines it is necessary to place Meters in a location away from the Point of Delivery, OPPD reserves the right to adjust its Meter readings and billings to account for delivery line losses.

Customers receiving service from more than one high voltage transmission source are restricted from tying or paralleling the sources at any time or for any duration. All transfers between sources must be performed as open transition transfers.

For planning purposes, the Customer will notify OPPD of their expected monthly Demand (in kilowatts) at least one week before the start of each month. In the event the Customer's actual monthly Demand varies by five (5) or more megawatts, OPPD reserves the right to request more frequent notifications regarding expected Loading conditions.

Under OPPD's Service Regulations, the resale, redistribution, marketing or extension of Electric Service received by the Customer, including in any wholesale or other markets, is prohibited. Customers are prohibited from taking wholesale transmission services to serve their Demand.

Customers served under this Rate Schedule shall not export power on OPPD's electrical system.

Service Regulations
Customers under this Rate Schedule must comply with all OPPD Service Regulations.

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RATE SCHEDULE NO. 236

Dusk-to-Dawn Lighting

APPLICABILITY

This Rate Schedule is applicable to all Customers, for private outdoor lighting service, when such lighting facilities are operated as an extension of OPPD's distribution system, except for:

- Installations on public or semi-public thoroughfares including public parks, where such installations would conflict with a legally constituted public authority having jurisdiction, and
- Athletic fields covered by other Rate Schedules.

Customers taking Electric Service as single-phase alternating current, 120 volts, will be supplied by OPPD for the operation of outdoor-type light fixtures using mercury vapor, high-pressure sodium, or LED lamps mounted on OPPD-owned wood poles on which overhead secondary conductors exist, or to which such secondary conductors can be extended, except where the extension of such secondary conductors is impractical.

This service will be unmetered, and the light fixtures will operate each night automatically from dusk to dawn. All facilities necessary for service under this Rate Schedule will be installed, owned and maintained by OPPD. This service is for the exclusive use of the Customer for private outdoor lighting as specified and cannot be resold to others.

Availability of the 175-watt and the 400-watt mercury vapor light fixture is restricted to existing units. As existing 175-watt and 400-watt mercury vapor units require maintenance, OPPD will replace them with their nominal equivalent LED units.

BILLING COMPONENTS

Monthly Rate:

For an installation on an existing wood pole and connected to existing overhead secondary conductors on such pole:

Lamp Size (watts)	Lamp Type	Per Unit Charge
100	7,200 lumen high-pressure sodium light fixture	$15.37~~14.06~~
175	7,000 lumen mercury-vapor light fixture*	$16.92~~15.48~~
200	22,000 lumen high-pressure sodium light fixture	$19.70~~18.69~~
400	20,000 lumen mercury-vapor light fixture*	$22.43~~20.52~~
33	LED	$13.02
108	LED	$17.76

Where an extension of overhead secondary facilities is required, and where such extension is acceptable to OPPD, the monthly rate will be increased by:

Charges as Required	Per Unit Charge
Additional transformer installed*	$6.68
Additional pole installed	$1.67
Additional span of secondary conductors installed	$0.85

**Restricted to existing Customers.*

Rider Schedule No. 461 – Fuel and Purchased Power Adjustment applies to this Rate Schedule.

Late Payment Charge:

A Late Payment Charge in the amount of 4% of the Billing Components and applicable taxes will be assessed if the current month's bill payment is not received by OPPD on or before the due date.

ADMINISTRATIVE

Contract Period

On initial installation of a light at a given location, the term of contract for service under this Rate Schedule will be for a period of two (2) years. After the two (2) year period, the service will continue until the customer contacts OPPD to request to have the light removed.

Special Conditions

Resolution No. 5733 states OPPD's Management has been authorized to add, delete, or restrict lighting rates in Rate Schedule No. 236 – Dusk to Dawn Lighting and Rate Schedule No. 350 – Municipal Service Street Lighting at any time, provided that any changes will be:

- Based on generally accepted cost-of-service ratemaking principles,
- Reviewed by the Board of Directors' rate consultant, and
- Approved by the Board of Directors during the next meeting at which the Board considers any rate action.

Service Regulations

Customers under this Rate Schedule must comply with all OPPD Service Regulations.

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RATE SCHEDULE NO. 350

Municipal Service Street Lighting

APPLICABILITY

This Rate Schedule is applicable to the State of Nebraska, and all Counties, Cities, Villages and Sanitary Improvement District's throughout OPPD's Service Area. The single-phase alternating current Electric Service will be supplied at OPPD's standard voltages for the operation of street lighting systems for public highways, streets, and thoroughfares.

Units of street lighting not priced in Parts 1 or 2 will be priced explicitly in the street lighting contract.

Each Customer shall enter into a contract with OPPD for street lighting service. Such a contract shall be for a period of one year, or longer, at OPPD's option, and shall include a reference to this street lighting Schedule and the Service Regulations of OPPD.

OPPD, at its discretion, may replace decorative units with like decorative units if the original decorative unit is no longer available or is not available at a reasonable cost.

BILLING COMPONENTS

Billing Procedure: Annual rates will be billed in 12 equal monthly installments.

Late Payment Charge:

A Late Payment Charge in the amount of 4% of the Billing Components and applicable taxes will be assessed if the current month's bill payment is not received by OPPD on or before the due date.

Rider Schedule No. 461 – Fuel and Purchased Power Adjustment applies to this Rate Schedule. The adjustment will be applied to the monthly energy usage for each lighting method based on the relevant light source and lamp size for such method.

Municipal Service Street Lighting:

Part 1 – OPPD Owned and Maintained System

Category No. 1: Standard Utility Style Lighting Methods Annual Rate: H.P. Sodium Light Source

Overhead Wiring: OPPD-Owned Pole

			Wood Pole		*Metal Pole*	
Method	Approx. Mounting Height (feet)	Lamp Size (watts)	Single Lamp	Twin Lamps	Single Lamp	Twin Lamps
61*	25	100	$200.16~~182.04~~	N/A	$231.36	N/A
65*	40	400	$367.92	N/A	$442.56	N/A
66*	30	200	$253.20~~237.72~~	N/A	$283.32	$391.68
67*	40	200	$270.84	N/A	$323.76	N/A
68*	30	400	$331.92	N/A	$417.36	N/A

*Restricted

Underground Wiring: OPPD-Owned Pole

			Wood Pole		*Metal Pole*	
Method	Approx. Mounting Height (feet)	Lamp Size (watts)	Single Lamp	Twin Lamps	Single Lamp	Twin Lamps
61*	25	100	N/A	N/A	$242.52	N/A
65*	40	400	N/A	N/A	$463.08	N/A
66*	30	200	$252.12	N/A	$299.52	$407.16
67*	40	200	N/A	N/A	$360.84	$461.52
68*	30	400	N/A	N/A	$432.96	$594.96

*Restricted

Underground Wiring: Customer-Owned Pole

Method	Approx. Mounting Height (feet)	Lamp Size (watts)	Single Lamp	Twin Lamps
61*	25	100	$179.04~~162.84~~	N/A
66*	30	200	$227.28~~206.64~~	N/A

*Restricted

Category No. 2: Standard Decorative Lighting Methods Annual Rate

Underground Wiring: OPPD-Owned Pole

Method	Approx. Mounting Height (feet)	Lamp Size (watts)	Light Source	Single Lamp	Twin Lamps
51	30	200	H.P. Sodium	$445.32	$618.72
52	25	100	H.P. Sodium	$382.80	$513.84
53	30	400	H.P. Sodium	$551.16	$898.20
57	30	400	Metal Halide	$555.00	N/A
58	40	400	H.P. Sodium	$576.36	$954.36
59	40	400	Metal Halide	$603.60	$830.52

Category No. 3: Restricted Lighting Methods Annual Rate

Overhead Wiring: OPPD-Owned Pole

				Wood Pole	*Metal Pole*	
Method	Approx. Mounting Height (feet)	Lamp Size (watts)	Light Source	Single Lamp	Single Lamp	Twin Lamps
14	30	400	Mercury Vapor	$319.32~~290.28~~	$341.64	$579.84
15	25	175	Mercury Vapor	$208.20~~189.36~~	$241.08~~230.76~~	N/A
16	25	100	Mercury Vapor	$172.92~~157.20~~	$218.40~~198.60~~	N/A
17	25	250	Mercury Vapor	$239.64~~217.92~~	$259.56	N/A
48	40	700	Mercury Vapor	$438.36	N/A	N/A
49	40	1,000	Mercury Vapor	N/A	$631.20	N/A
63	30	250	H.P. Sodium	$259.80~~236.28~~	$308.88	N/A

Underground Wiring: OPPD-Owned Pole

				Wood Pole	*Metal Pole*	
Method	Approx. Mounting Height (feet)	Lamp Size (watts)	Light Source	Single Lamp	Single Lamp	Twin Lamps
14	30	400	Mercury Vapor	$327.84~~307.08~~	$357.12	N/A
15	25	175	Mercury Vapor	$232.80~~211.68~~	$242.64	N/A
16	25	100	Mercury Vapor	N/A	$225.60~~210.48~~	N/A
17	25	250	Mercury Vapor	N/A	$271.20	N/A

44	40	400	Mercury Vapor	N/A	$411.84	N/A
49	40	1,000	Mercury Vapor	N/A	$608.16	N/A
62	30	400	H.P. Sodium	N/A	N/A	$679.56
63	30	250	H.P. Sodium	$262.32	$323.16	N/A
64	40	250	H.P. Sodium	N/A	$367.08	N/A

Underground Wiring: Customer-Owned Pole

Method	Approx. Mounting Height (feet)	Lamp Size (watts)	Light Source	Single Lamp	Twin Lamps
14	30	400	Mercury Vapor	$319.56~~290.52~~	N/A
15	25	175	Mercury Vapor	$189.72~~172.56~~	N/A

Category No. 4: Optional Decorative Lighting Methods Annual Rate

Decorative Method without Base: OPPD-Owned Pole

Method	Option	Approx. Mounting Height (feet)	Lamp Size (watts)	Light Source	Fixture	Single Lamp
90*	A	16	70	H.P. Sodium	Acorn	$342.60~~325.68~~
90	H	16	39	LED	Acorn	$374.52
93*	A	20	100	H.P. Sodium	Lantern	$310.80~~282.60~~
93*	E	20	51	LED	Lantern	$306.00~~287.88~~

*Restricted

Decorative Method Base and Ring: OPPD-Owned Pole

Method	Option	Approx. Mounting Height (feet)	Lamp Size (watts)	Light Source	Fixture	Single Lamp
90*	C	16	70	H.P. Sodium	Acorn	$347.52
90	I	16	39	LED	Acorn	$407.52
91*	C	16	70	H.P. Sodium	Globe	$507.48
91*	F	16	39	LED	Globe	$544.20
92*	C	20	100	H.P. Sodium	Top Hat	$296.16

*Restricted

Decorative Method Base and Ring and Outlet: OPPD-Owned Pole

Method	Option	Approx. Mounting Height (feet)	Lamp Size (watts)	Light Source	Fixture	Single Lamp
90	G	12	39	LED	Acorn	$498.84

Decorative Method Pay Up Front: OPPD-Owned Pole

Method	Approx. Mounting Height (feet)	Lamp Size (watts)	Light Source	Fixture	Single Lamp
07L	12 or 16	51	LED	Top Hat or Lantern	$217.56
08L	12 or 16	39	LED	Acorn or Globe	$211.44
09	14	66	LED	Bounce	$225.12
12*	12	70	H.P. Sodium	Acorn	$223.08
94*	16	70	H.P. Sodium	Acorn	$223.08
95*	16	70	H.P. Sodium	Globe	$233.76
96*	20	100	H.P. Sodium	Top Hat	$242.52
97*	20	100	H.P. Sodium	Lantern	$242.52
98*	14	150	Metal Halide	Bounce	$245.04

*Restricted

Category No. 5: LED Lighting Methods Annual Rate

Overhead Wiring: OPPD-Owned Pole

			Wood Pole		*Metal Pole*	
Method	Approx. Mounting Height (feet)	Lamp Size (watts)	Single Lamp	Twin Lamps	Single Lamp	Twin Lamps
61L	25	54	$136.08~~123.72~~	$208.32~~189.48~~	$189.72~~172.56~~	$258.48~~238.20~~
65L	40	207	$279.60~~268.68~~	N/A	$320.52	N/A
66L	30	108	$170.28~~154.80~~	$280.32~~254.88~~	$227.04~~211.20~~	$292.56~~285.60~~
67L	40	108	$192.84~~175.32~~	N/A	$227.76	N/A
68L	30	207	$276.96~~260.64~~	N/A	$301.20	N/A

Underground Wiring: OPPD-Owned Pole

	Wood Pole	*Metal Pole*

Method	Approx. Mounting Height (feet)	Lamp Size (watts)	Single Lamp	Twin Lamps	Single Lamp	Twin Lamps
51L	30	89	N/A	N/A	$350.52	$498.72
52L	25	46	N/A	N/A	$322.32	N/A
53L	30	89	N/A	N/A	$414.36	$666.84
58L	40	232	N/A	N/A	$427.20	$722.52
61L	25	54	$160.44~~145.92~~	$233.40~~212.28~~	$211.20~~192.72~~	$259.80~~255.00~~
65L	40	207	N/A	N/A	$356.28	N/A
66L	30	108	$202.92~~184.56~~	N/A	$243.84	$301.68
67L	40	108	$229.20~~224.52~~	$335.28	$270.12	$381.84
68L	30	207	N/A	N/A	$329.88	N/A

Underground Wiring: Customer-Owned Pole

Method	Approx. Mounting Height (feet)	Lamp Size (watts)	Single Lamp	Twin Lamps
51L	30	89	$254.16~~231.12~~	N/A
53L	30	89	$314.88~~286.68~~	N/A
58L	40	232	$316.44~~298.32~~	N/A
61L	25	54	$134.76~~122.52~~	N/A
65L	40	207	$277.32~~259.80~~	$442.08
66L	30	108	$166.80~~151.68~~	N/A
67L	40	108	$196.68~~178.80~~	$294.48

Category No. 5: LED Lighting Methods Annual Rate with Additional Agreements Required

Overhead Wiring: OPPD-Owned Pole

Method	Approx. Mounting Height (feet)	Lamp Size (watts)	Wood Pole	Metal Pole
29	30	100	$110.16~~100.20~~	N/A

30	30	200	$128.28~~116.64~~	N/A
31	40	200	$164.40~~149.52~~	N/A

Underground Wiring: OPPD-Owned Pole

Method	Approx. Mounting Height (feet)	Lamp Size (watts)	Wood Pole	Metal Pole
28	25	100	N/A	$170.40~~154.92~~
31	40	200	N/A	$236.04

Part 2 – Customer-Owned System Operated by OPPD Annual Method

Method	Lamp Size (watts)	Light Source	Dusk to Dawn
22	250	Mercury Vapor	$142.68~~129.72~~
23	400	Mercury Vapor	$207.72~~188.88~~
24	700	Mercury Vapor	$311.40~~302.16~~
25	1,000	Mercury Vapor	$412.32
25L	529	LED	$223.80~~203.52~~
40	54	LED	$61.20~~55.68~~
42	48	LED	$56.28~~51.24~~
71	100	H.P. Sodium	$92.40~~84.00~~
71L	58	LED	$66.60~~60.60~~
72	150	H.P. Sodium	$112.80~~102.60~~
73	250	H.P. Sodium	$149.40~~135.84~~
74	400	H.P. Sodium	$215.88~~196.32~~

74L	207	LED	$111.84~~101.76~~
76	200	H.P. Sodium	$128.88~~117.24~~
76L	108	LED	$79.56~~72.36~~
76LT	108	Twin LED	$114.96~~104.52~~
77	50	H.P. Sodium	$64.92~~59.04~~
77L	25	LED	$54.12~~49.20~~
78	70	H.P. Sodium	$72.60~~66.00~~
79	1,000	H.P. Sodium	$421.92
80	100	Metal Halide	$84.00~~76.44~~
80L	65	LED	$68.64~~62.40~~
81	175	Metal Halide	$112.68~~102.48~~
81L	48	LED	$62.04~~56.40~~
81LT	48	Twin LED	$77.28~~70.32~~
82	250	Metal Halide	$143.16~~130.20~~
82L	100	LED	$78.36~~71.28~~
83	400	Metal Halide	$200.76~~182.52~~
87	50	Metal Halide	$63.60~~57.84~~

OPPD has the option of furnishing maintenance service to Part 2 streetlights on a reimbursable basis. The terms and conditions of such service will be set forth in individual contracts.

Part 3 – Rate for Customer's providing poles to OPPD for 5G pole attachments.

Method	Lamp Size (watts)	Light Source	Dusk to Dawn
75L	54	LED	$61.80~~56.28~~

ADMINISTRATIVE

Definitions

Method: Identifies the specific combination of features (light source, mounting height, lamp size, and the number of lamps) that comprise an individual streetlight.

Customer-Owned Poles and Fixtures: Poles and fixtures, provided by the Customer, to which OPPD adds OPPD-owned streetlight equipment and separate service wiring.

Units: One or more components, including the fixture, lamp, photocell, and pole, which comprise a streetlight.

Special Conditions
Resolution No. 5733 states OPPD's Management has been authorized to add, delete, or restrict lighting rates in Rate Schedule No. 236 – Dusk to Dawn Lighting and Rate Schedule No. 350 – Municipal Service Street Lighting at any time, provided that any changes will be:

- Based on generally accepted cost-of-service ratemaking principles,
- Reviewed by the Board of Directors' rate consultant, and
- Approved by the Board of Directors during the next meeting at which the Board considers any rate action.

Service Regulations
Customers under this Rate Schedule must comply with all OPPD Service Regulations.

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RATE SCHEDULE NO. 351

Municipal Services Traffic Signals and Signs

APPLICABILITY

This Rate Schedule is applicable to all governmental agencies throughout OPPD's Service Area where service for such purpose is reasonably available, and the use of service can reasonably be controlled and calculated without metering.

Governmental agencies taking Electric Service as single-phase alternating current will be supplied at OPPD's standard voltages for the operation of Traffic Signals, Signs, Flashers, Counters or other devices used in the general control of thoroughfare traffic.

BILLING COMPONENTS

Energy Charge:

Energy Usage	All Months (Jan. 1 – Dec.31)
kWh	10.029~~9.832~~ cents/kWh

Rider Schedule No. 461 – Fuel and Purchased Power Adjustment applies to this Rate Schedule.

Minimum Monthly Bill: $3.01 per location.

Late Payment Charge:

A Late Payment Charge in the amount of 4% of the Billing Components and applicable taxes will be assessed if the current month's bill payment is not received by OPPD on or before the due date.

Determination of Energy

When service at a location is used continuously, day and night, the average watts in use will be multiplied by 730 hours and divided by 1000.

When service at a location is not used during daylight hours and is disconnected by a control device during such hours, the average watts in use from dusk to dawn will be multiplied by 360 hours and divided by 1000.

Gaseous tube lighting or other low Power Factor devices will be corrected to not less than 90 percent Power Factor.

ADMINISTRATIVE

Special Conditions

Customers taking service under this Rate Schedule agree to:

- Furnish OPPD all information necessary to calculate the monthly kilowatt-hour use
- Notify OPPD immediately of any permanent change in their Load that will affect the kilowatt-hours used
- Cooperate with OPPD to periodically verify Load

Service Regulations

Customers under this Rate Schedule must comply with all OPPD Service Regulations.

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RATE SCHEDULE NO. 357

Municipal Service

APPLICABILITY

This Rate Schedule is applicable to all Municipal Utilities throughout OPPD's Service Area.

Municipalities taking Electric Service as three-phase alternating current will be supplied by OPPD at a voltage not less than 2400 volts for use through a municipally owned and maintained distribution system.

BILLING COMPONENTS

Monthly Service Charge: $143.90 per month

plus, Demand Charge:

Billing Demand	Per kW Month
Per kW	$12.90~~12.03~~

Energy Charge:

Energy Usage	Three-Phase
Per kWh	4.937 ~~4.71~~ cents/kWh

Rider Schedule No. 461 – Fuel and Purchased Power Adjustment applies to this Rate Schedule.

Minimum Monthly Bill: The minimum monthly bill will be the monthly service charge plus the charge for the currently effective Demand.

Late Payment Charge:

A Late Payment Charge in the amount of 4% of the Billing Components and applicable taxes will be assessed if the current month's bill payment is not received by OPPD on or before the due date.

Determination of Demand

Demand, for any billing period, will be the kilowatts computed from the readings of OPPD's kilowatt-hour Meter for the 15-minute interval of the Customer's highest use during the same billing period.

If the Demand is less than 85% of the Customer's highest 15-minute kilovolt-ampere Demand, the kilowatt Demand will be increased under this Schedule by 50% of the difference between 85% of the kilovolt-ampere Demand and the Demand as determined above.

The Customer's Demand must be equal to or greater than the larger of the following:

- 85% of the highest 15-minute Power Factor adjusted-Demand during the Summer billing months of the preceding eleven (11) months, or
- 60% of the highest 15-minute Power Factor adjusted-Demand during the Non-Summer billing months of the preceding eleven (11) months.

ADMINISTRATIVE

Special Conditions

Special Conditions will be included in the contract and will be mutually agreed upon by both parties. This Rate Schedule will be included as part of the contract.

Service Regulations

Customers under this Rate Schedule must comply with all OPPD Service Regulations.

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RATE SCHEDULE NO. 230M

General Service Non-Demand – Offutt Housing Adjustment Rider

APPLICABILITY

This Rate Schedule is applicable to all Customers within the designated privatized housing areas at Offutt Air Force Base (Offutt AFB) that have monthly Billing Demands less than 50 kilowatts during each of the four (4) Summer billing months.

Customers taking Electric Service as single-phase or three-phase alternating current will be supplied at OPPD's standard voltages, for all uses, when all the Electric Services at one location is measured by one Meter, unless the Customer takes emergency or special service as required by OPPD's Service Regulations. Not applicable to shared or resale service.

This rate is not available to those Customers taking service under Rate Schedule No. 226 – Irrigation Service.

The charges as determined under Rate Schedule No. 230 – General Service – Non-Demand will apply to this Rate Schedule.

BILLING COMPONENTS

Monthly Service Charge: $33.00 per month plus,

Energy Charge:

Energy Usage Per kWh	Summer (June 1 – Sept. 30)	Non-Summer (Oct. 1 – May 31)
	11.116 cents/kWh	8.717 cents/kWh

Offutt Adjustment

A credit adjustment will be applied per kilowatt-hour to all energy billed during the current billing period. The adjustment will be capped so that Customers will not have a rate higher than Rate Schedule No. 230 – General Service Non-Demand. The adjustment will be based on the production cost differential determined by OPPD as follows:

OPPD Cost of Production less WAPA Cost of Production, determined on a cents per kWh basis, applicable to Rate Schedule No. 230 – General Service Non-Demand.

Minimum Monthly Bill: $33.00

The minimum monthly bill is the monthly service charge. Any energy used by the Customer during a billing period is charged in addition to the minimum bill.

Late Payment Charge:

A Late Payment Charge in the amount of 4% of the Billing Components and applicable taxes will be assessed if the current month's bill payment is not received by OPPD on or before the due date.

ADMINISTRATIVE

Definitions

OPPD's Cost of Production: Costs related to the capacity and amount of electricity produced at each of OPPD's generating plants, purchased power for use by OPPD's Customers, and credits for interchange sales through OPPD's system.

Western Area Power Authority (WAPA) Cost of Production: Actual cost of generation provided by WAPA and assigned to OPPD for delivery to Offutt AFB.

Service Regulations

Customers under this Rate Schedule must comply with all OPPD Service Regulations.

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RATE SCHEDULE NO. 230M

~~Effective 1/1/2027~~

General Service Non-Demand – Offutt Housing Adjustment Rider

APPLICABILITY

This Rate Schedule is applicable to all Customers within the designated privatized housing areas at Offutt Air Force Base (Offutt AFB) that record an average actual monthly Demand of less than or equal to 50 kilowatts during the four (4) Summer billing months, June through September.

This rate is not available to those Customers taking service under Rate Schedule No. 226 – Irrigation Service.

The charges as determined under Rate Schedule No. 230 – General Service – Non-Demand will apply to this Rate Schedule.

BILLING COMPONENTS

Monthly Service Charge: $33~~.~~~~00~~ per month plus,

Energy Charge:

Energy Usage	Summer (June 1 – Sept. 30)	Non-Summer (Oct. 1 – May 31)
Per kWh	12.329~~00~~ cents/kWh	9.271~~00~~ cents/kWh

Rider Schedule No. 461 – Fuel and Purchased Power Adjustment applies to this Rate Schedule.

Offutt Adjustment

A credit adjustment will be applied per kilowatt-hour to all energy billed during the current billing period. The adjustment will be capped so that Customers will not have a rate higher than Rate Schedule No. 230 – General Service Non-Demand. The adjustment will be based on the production cost differential determined by OPPD as follows:

OPPD Cost of Production less WAPA Cost of Production, determined on a cents per kWh basis, applicable to Rate Schedule No. 230 – General Service Non Demand.

Minimum Monthly Bill: $33~~.00~~

The minimum monthly bill is the monthly service charge. Any energy used by the Customer during a billing period is charged in addition to the minimum bill.

Late Payment Charge:

A Late Payment Charge in the amount of 4% of the Billing Components and applicable taxes will be assessed if the current month's bill payment is not received by OPPD on or before the due date.

ADMINISTRATIVE

Definitions

OPPD's Cost of Production: Costs related to the capacity and amount of electricity produced at each of OPPD's generating plants, purchased power for use by OPPD's Customers, and credits for interchange sales through OPPD's system.

Western Area Power Authority (WAPA) Cost of Production: Actual cost of generation provided by WAPA and assigned to OPPD for delivery to Offutt AFB.

Service Regulations

Customers under this Rate Schedule must comply with all OPPD Service Regulations.

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RATE SCHEDULE NO. 231M

General Service – Demand – Offutt Housing Adjustment Rider

APPLICABILITY

This Rate Schedule is applicable to all non-Residential Customers within the designated privatized housing areas at Offutt Air Force Base (Offutt AFB) that meet or exceed a Billing Demand of 50 kilowatts during one of the four (4) Summer billing months, June through September.

Customers taking Electric Service as single phase (or three phase, if available) alternating current, will be supplied at OPPD's standard voltages, for all uses, when all the Electric Services at one location is measured by one Meter with a Demand register, unless the Customer takes emergency or special service as required by OPPD's Service Regulations. Not applicable to shared or resale service.

This rate is not available to those Customers taking service under Rate Schedule No. 226 – Irrigation Service.

The charges as determined under Rate Schedule No. 231 – General Service – Demand will apply to this Rate Schedule.

BILLING COMPONENTS

Monthly Service Charge: $19.86 per month plus,

Demand Charge:

Billing Demand	Per kW Month
Per kW	$8.62

Minimum Billing Demand of 18 kW per month.

Energy Charge:

Energy Usage	Summer (June 1 – Sept. 30)	Non-Summer (Oct. 1 – May 31)
Per kWh	6.997 cents/kWh	5.669 cents/kWh

Rider Schedule No. 461 – Fuel and Purchased Power Adjustment applies to this Rate Schedule.

Offutt Adjustment

A credit adjustment will be applied per kilowatt-hour to all energy billed during the current billing period. The adjustment will be capped so that Customers will not have a rate higher than Rate Schedule No. 231 – General Service – Small Demand. The adjustment will be based on the production cost differential determined by OPPD as follows:

OPPD Cost of Production less WAPA Cost of Production, determined on a cents per kWh basis, applicable to Rate Schedule No. 231 – General Service – Small Demand.

Minimum Monthly Bill: $175.02

The minimum monthly bill is calculated as the 18 kilowatt minimum Demand requirements of $155.16, plus the monthly service charge of $19.86. Any energy used by the Customer during a billing period is charged in addition to the minimum bill.

Late Payment Charge:

A Late Payment Charge in the amount of 4% of the Billing Components and applicable taxes will be assessed if the current month's bill payment is not received by OPPD on or before the due date.

Determination of Demand

Demand, for any billing period, will be the kilowatts computed from the readings of OPPD's Meter for the 15-minute interval of the Customer's highest use during the same billing period.

If the Demand is less than 85% of the Customer's highest 15-minute kilovolt-ampere Demand, the kilowatt Demand will be increased under this Schedule by 50% of the difference between 85% of the kilovolt-ampere Demand and the Demand as determined above.

The Customer's Demand must be equal to or greater than the larger of the following:

- 85% of the highest 15-minute Power Factor-adjusted Demand during the summer billing months of the preceding eleven (11) months, or
- 60% for the highest 15-minute Power Factor-adjusted Demand during the Non-Summer billing months of the preceding eleven (11) months, or
- 18 kilowatts

ADMINISTRATIVE

Definitions

OPPD's Cost of Production: Costs related to the capacity and amount of electricity produced at each of OPPD's generating plants, purchased power for use by OPPD's Customers, and credits for interchange sales through OPPD's system.

Western Area Power Authority (WAPA) Cost of Production: Actual cost of generation provided by WAPA and assigned to OPPD for delivery to Offutt AFB.

Service Regulations

Customers under this Rate Schedule must comply with all OPPD Service Regulations.

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RATE SCHEDULE NO. 231M

~~EFFECTIVE 1/1/2027~~

General Service – Demand – Offutt Housing Adjustment Rider

APPLICABILITY

This Rate Schedule is applicable to all non-Residential Customers within the designated privatized housing areas at Offutt Air Force Base (Offutt AFB) that record an average actual monthly Demand of greater than 50 kilowatts and less than or equal to 3,000 kilowatts during the four (4) Summer billing months, June through September.

This rate is not available to those Customers taking service under Rate Schedule No. 226 – Irrigation Service.

The charges as determined under Rate Schedule No. 231 – General Service – Demand will apply to this Rate Schedule.

BILLING COMPONENTS

Monthly Service Charge: $19.86~~—~~ per month plus,

Demand Charge:

Billing Demand	Per kW Month
Per kW	$9.84~~—~~

Minimum Billing Demand of 42~~18~~ kW per month.

Energy Charge:

Energy Usage	Summer (June 1 – Sept. 30)	Non-Summer (Oct. 1 – May 31)
Per kWh	7.757~~—~~ cents/kWh	5.820~~—~~ cents/kWh

Rider Schedule No. 461 – Fuel and Purchased Power Adjustment applies to this Rate Schedule.

Offutt Adjustment

A credit adjustment will be applied per kilowatt-hour to all energy billed during the current billing period. The adjustment will be capped so that Customers will not have a rate higher than Rate Schedule No. 231 – General Service – Small Demand. The adjustment will be based on the production cost differential determined by OPPD as follows:

OPPD Cost of Production less WAPA Cost of Production, determined on a cents per kWh basis, applicable to Rate Schedule No. 231 – General Service – Small Demand.

Minimum Monthly Bill: $433.14~~—~~

The minimum monthly bill is calculated as the 42-kilowatt minimum Demand requirements of $413.28~~—~~, plus the monthly service charge of $19.86~~—~~. Any energy used by the Customer during a billing period is charged in addition to the minimum bill.

Late Payment Charge:

A Late Payment Charge in the amount of 4% of the Billing Components and applicable taxes will be assessed if the current month's bill payment is not received by OPPD on or before the due date.

Determination of Demand

Demand, for any billing period, will be the kilowatts computed from the readings of OPPD's Meter for the 15-minute interval of the Customer's highest use during the same billing period.

If the Demand is less than 85% of the Customer's highest 15-minute kilovolt-ampere Demand, the kilowatt Demand will be increased under this Schedule by 50% of the difference between 85% of the kilovolt-ampere Demand and the Demand as determined above.

The Customer's Demand must be equal to or greater than the larger of the following:

- 85% of the highest 15-minute Power Factor-adjusted Demand during the summer billing months of the preceding eleven (11) months, or
- 60% for the highest 15-minute Power Factor-adjusted Demand during the Non-Summer billing months of the preceding eleven (11) months, or
- 18 kilowatts

ADMINISTRATIVE

Definitions

OPPD's Cost of Production: Costs related to the capacity and amount of electricity produced at each of OPPD's generating plants, purchased power for use by OPPD's Customers, and credits for interchange sales through OPPD's system.

Western Area Power Authority (WAPA) Cost of Production: Actual cost of generation provided by WAPA and assigned to OPPD for delivery to Offutt AFB.

Service Regulations

Customers under this Rate Schedule must comply with all OPPD Service Regulations.

RIDER SCHEDULES

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RIDER SCHEDULE NO. 355

Electric Energy Purchased from
Cogenerating and Small Power Producing Facilities

APPLICABILITY

This Rider Schedule is applicable to all Customers who have qualified cogenerating or Small Power Producing Facilities that have the appropriate metering to measure the delivery of electric energy to OPPD.

BILLING COMPONENTS

For facilities with less than 1000 kW of generating capacity:

Service Charge: $4.00 per Meter per month

Energy Credit:
OPPD will pay the Customer based on the type of metering installed as follows:

No Meter: No Rate

	Summer (June 1 – Sept. 30)	Non-Summer (Oct. 1 – May 31)
All Hours	4.00 cents/kWh	3.52 cents/kWh

Time of Day	Summer (June 1 – Sept. 30)	Non-Summer (Oct. 1 – May 31)
On-Peak Hours: 6:00AM – 10:00PM M–F	5.40 cents/kWh	4.39 cents/kWh
Off-Peak Hours: All Other Hours	2.73 cents/kWh	2.73 cents/kWh

For facilities with 1000 kilowatts or more of generating capacity, the rate will be based on OPPD's avoided costs and will be established for each facility.

ADMINISTRATIVE

Special Conditions

A written agreement between the Customer and OPPD is required. OPPD will not operate in parallel without a contract.

The Customer will pay for the additional equipment required for parallel operation and installation costs, as outlined in the agreement, before the initiation of parallel operation.

The interconnection of this equipment with OPPD's system must meet the standards specified in the OPPD policy for "Parallel Operation of Customer-Owned Generation Equipment." All required policies can be found at https://www.oppd.com.

Service Regulations

Customers under this Rider Schedule must comply with all OPPD Service Regulations.

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RIDER SCHEDULE NO. 461

Fuel and Purchased Power Adjustment

APPLICABILITY

This Rider Schedule is applicable to all Customers throughout OPPD's Service Area that take electrical service under OPPD's Rate Schedule Nos. 110, 115, 120, 226, 230, 231, 232, 236, 245, -350, 351, or 357.

This Schedule applies an adjustment per kilowatt-hour to all retail and municipal service energy sales to reflect changes in fuel and purchased power expenses that are above, or below, the Fuel and Purchased Power Base Rate.

BILLING COMPONENTS

FPPA Charge:

The Customer's monthly bill will reflect a Fuel and Purchased Power Adjustment (FPPA) applied to the monthly kilowatt-hour usage.

FPPA Annual Calculation

The FPPA is calculated as follows:

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

Where:

NEC = Annual Budgeted Net Energy Costs = (FC +C +PP –OSSR)

- FC = Fuel Costs: These are the costs incurred to support the generation of electricity
- C = Consumables: Materials that are 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 Revenue: Revenues from Southwest Power Pool transactions associated with off-system sales

O = Over/Under Balance: For any given period, the Over/Under variance is the difference between the actual net energy costs and the revenue generated by the FPPA Base Rate plus the FPPA in effect during the period

S = Actual Budgeted Energy Sales: Budgeted kilowatt-hour sales to retail and municipal service customers

F = Fuel and Purchase Power Base Rate: 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 2.497~~1.951~~ cents per kilowatt-hour

OPPD will adjust the FPPA annually on January 1st of each year and will calculate the FPPA before that date. To facilitate that calculation, OPPD will establish its fuel and purchased power budget for the year in advance of January 1st of that year. The Over/Under Balance to be included in the FPPA will be the amount approximately three (3) months before January 1 of the upcoming year, plus the projected amounts for the remainder of the calendar year. The amount will be transferred from the Over/Under Balance to the FPPA. Accordingly, the Over/Under Balance will be adjusted by the amount to be included in the FPPA.

ADMINISTRATIVE

Special Conditions

OPPD reserves the right to modify the FPPA at any time, with approval of the Board of Directors.

Service Regulations

Customers under this Rider Schedule must comply with all OPPD Service Regulations.

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RIDER SCHEDULE NO. 462

Primary Service Discount

APPLICABILITY

This Rider Schedule is applicable to Customers taking single-phase or three-phase service from OPPD at a standard available voltage above 11,000 volts, provided there is only one transformation involved from an OPPD transmission voltage (above 60,000 volts) to the service voltage.

This Rider Schedule is not available to those Customers taking service under Rate Schedule Nos. 245 or 261M.

BILLING COMPONENT

The monthly credit will be calculated as a percent of the monthly bill as determined by the applicable Rate Schedule:

Delivery Voltage	Discount
4,000 to 60,000	3%
60,001+	5%

ADMINISTRATIVE

Special Conditions

OPPD may change its standard delivery voltage to any affected Customer receiving a discount after advanced written notice. The Customer has the option to change their system to receive service at the new standard delivery voltage or to accept service without the Primary Service Discount after the change in delivery voltage through transformers owned by OPPD.

Service Regulations

Customers under this Rider Schedule must comply with all OPPD Service Regulations.

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RIDER SCHEDULE NO. 464

Standby Service

APPLICABILITY

This Rider Schedule is applicable to all Customers normally serving all or a portion of their own electrical or mechanical Load from Customer-Owned equipment when the sum of the combined nameplate rating of the primary generator(s) and the combined nameplate rating of the mechanical Load converted to Equivalent Electrical Load in excess of 25 kW. (The primary generator(s) and the Equivalent Electrical Load shall be referred to as "Units.")

This Rider Schedule does not apply to Units operated for emergency purposes, to Emergency Generating Unit(s), Auxiliary Generating Unit(s) operated as standby to the Customer's Units, or for Load not requiring Standby Service (Load is permanently isolated from OPPD's System), for shared service, or as leased capacity to OPPD under Rate Schedule No. 467L. This Rider Schedule is not mandatory for Customer-Owned renewable energy equipment.

BILLING COMPONENTS

Standby Service Option No. 1 – Standby Service for the Customer's Units
Standby Service Option No. 2 – Standby Service with separate status (on/off) metering of the primary, auxiliary, and mechanical generating unit(s):

Monthly Service Charge:

Standby Service Option	Monthly Rate
Standby Option 1:	No Rate
Standby Option 2:	$45.45

Standby Charge:

Electric Service Level	*Standby Option 1*:	*Standby Option 2*:
Primary Level	$5.08/kW of Contract Demand	$5.08/kW of Contract Demand
Secondary Level	$5.55/kW of Contract Demand	$5.55/kW of Contract Demand

Rider Schedule No. 462 – Primary Service Discount does not apply to this Rider Schedule.

Determination of Contract Demand (Applies to Options 1 and 2)
Where OPPD is required to stand ready to supply Standby Service, the Contract Demand shall be equal to:

(1) the Load normally isolated from OPPD's System by a throw-over switch and normally served by the Customer's equipment, and/or

(2) the nameplate rating of the Customer's Primary Generating Unit(s) normally operated in parallel with OPPD's System if the nameplate rating of the Primary Generating Unit(s) is less than the maximum 15-minute peak Demand of the Customer's facility, or

(3) the maximum 15-minute peak Demand of the Customer's facility if the nameplate rating of the Primary Generating Unit(s) normally operated in parallel with OPPD's system is greater than the maximum 15-minute peak Demand of the Customer's facility, whichever is applicable.

The Customer may arrange for OPPD to supply Standby Service for a portion of the Load normally isolated from OPPD's System with a throw-over switch and normally served by the Customer's equipment. The Customer will furnish and install suitable switchgear to reduce Demand to the Contract Demand level when the Customer's Demand exceeds the Contract Demand during an outage of the Customer's equipment. The switchgear furnished by the Customer shall be approved by OPPD and will be under exclusive OPPD control.

Demand and Energy Charges (Applies to Options 1 and 2)

The charges, as determined under the regular Rate Schedule, apply to the service rendered.

However, if an increase in Billing Demand occurs in the current billing period as a result of a total outage of one or more of the Customer's primary or mechanical generating unit(s) and the failure of the auxiliary unit(s) to operate as back-up to the primary unit(s) or the Equivalent Electrical Load, the current month's Standby Charge will be reduced. The reduction will be based on the difference between the Billing Demand, as determined from the highest actual Meter reading occurring during such outage interval, and the Billing Demand, as determined from the Reference Demand.

The Reference Demand is the highest Demand resulting from any 15-minute Meter reading occurring during the current billing period being reduced by any portion of the Customer's Contract Demand not served by the Customer's equipment during such 15- minute period. The resulting Reference Demand will not be established higher than the original 15-minute Meter reading.

If, in the current billing period, the actual metered Demand during such outage interval is greater than the maximum metered Demand during any non-outage period, the Reference Demand will be used in the determination of charges for the next 11 months.

Standby Service Option No. 3 – Waiver of Standby Charge by designation of a Firm Demand:

Standby Charge:

Electric Service Level	Standby Option 3:
Excess Demand Charge	Applies

Rate Schedule No. 462 – Primary Service Discount does not apply to this Rate Schedule.

Demand and Energy Charges (Applies to Option 3)

The charges as determined under the regular Rate Schedule applicable to the service rendered with the exception that the Demand used to calculate the monthly bill will be determined as outlined in the "Determination of Billing Demand" clause within this Rate Schedule.

Excess Demand Charge (Applies to Option 3)

The current levelized cost of a combustion turbine peaking unit, including fixed capital and operation and maintenance cost. This charge will be increased by 23% to recover costs associated with the reserve margin and Demand losses on the transmission and distribution system. The resultant charge will be applied to the Customer's Excess Demand.

Designation of Demand (Applies to Option 3)

The Customer must (1) designate a Firm Demand for the facility to be served under this Rate Schedule and (2) declare the nameplate rating of the Customer's Units.

If the maximum potential Demand of a Customer's facility exceeds the supply capability of OPPD's electrical network at that location, the Customer will furnish and install suitable switchgear to limit Demand to a level determined by OPPD. This level will be no less than the Firm Demand level.

Determination of Billing Demand (Applies to Option 3)

The Customer's monthly Billing Demand will be determined by (a) the Power Factor-adjusted Demand, as calculated in the "Determination of Demand" clause in the applicable Rate Schedule subject to Demand minimums, or (b) the Firm Demand, whichever is greater.

Determination of Excess Demand Charges (Applies to Option 3)

If the Customer's Power Factor adjusted Demand exceeds the Firm Demand during the On-Peak Periods of any calendar year, the Customer will be assessed the Excess Demand Charge for the difference between the Firm Demand and the Power Factor adjusted Demand in the current month. The Excess Demand Charge will be assessed only once for each kW for which the Power Factor Adjusted-Demand exceeds the Firm Demand during the On-Peak Periods in any calendar year.

Minimum Monthly Bill

The minimum monthly bill from the regular Rate Schedule, applicable to the service rendered, plus the charges for the applicable Standby Service Option.

ADMINISTRATIVE

Schedule Duration:

A minimum of three years, pursuant to a written agreement. Said agreements, at their expiration dates, will automatically be renewed for additional two-year periods unless cancelled by written notice by either party at least six months before the expiration dates.

Customers may elect to take service under a different Standby Service Option only after the current option has been in effect for at least 12 months. The Customer will provide written notice to OPPD of their intention to change options sixty (60) days before the proposed effective date of such change.

For those Customers whose Contract Demand is determined according to Condition No. 1 or Condition No. 3 in the "Determination of Contract Demand" clause within this Rate Schedule, the level of the Contract Demand will be reviewed annually.

For Standby Service Option No. 3, the Firm Demand may be decreased only after the current Firm Demand has been in place for at least 12 months. The Customer will provide written notice to OPPD of their intention to decrease the Firm Demand 30 days before the proposed effective date of such decrease.

The Firm Demand may be increased according to the following conditions:

1. For increases in the Firm Demand that are greater than 20 MW, the Customer will provide written notice to OPPD of their intention to increase the Firm Demand at least six months before the proposed effective date of the increase.

2. For increases in the Firm Demand that are less than or equal to 20 MW, the Customer will provide written notice to OPPD of their intention to increase the Firm Demand at least three months before the proposed effective date of the increase.

Definitions
Contract Demand: The nameplate capacity of the Customer's Primary Generating Unit(s) or the Equivalent Electrical Load normally isolated from OPPD's System and served by a Customer's generating equipment.

Equivalent Electrical Load: The electrical power required to operate mechanical Load at the nameplate horsepower. One horsepower will be converted to Equivalent Electrical Load using an 85% efficiency. (One horsepower mechanical equals 877 watts electrical.)

On-Peak Periods: Monday through Friday between the hours of 12:00 P.M. and 10:00 P.M. during the months of June, July, August, and from September 1 through September 15, excluding Federal Holidays.

Firm Demand: The Demand to be served by OPPD that the Customer expects to be served by OPPD in normal operation during the On-Peak Periods.

Excess Demand: The amount of the Customer's Demand served by OPPD that exceeds the Firm Demand during the On-Peak Periods.

Special Conditions
OPPD will not be required to furnish more than one Standby Service Option for a Customer taking service at one location.

OPPD will not be required to furnish duplicate service hereunder.

The Customer shall reimburse OPPD for all metering and switchgear equipment and the maintenance of such equipment necessary to administer this Rate Schedule.

Any metering and switchgear equipment installed, for purposes of this Rate Schedule, on the Customer's side of the Meter by the Customer must be approved by OPPD and must be installed and maintained to provide a safe environment for OPPD's and Customer's personnel.

Any metering and switchgear located on the Customer's side of the Meter must be inspected by OPPD and tested before being energized and tested once a year after that with the results of the tests reviewed and approved by OPPD.

All installations must be in conformance with the National Electrical Safety Code.

OPPD will not be liable for any damage to a Customer's equipment due to the failure of any metering or switchgear installed by the Customer on the Customer's side of the Meter.

Service Regulations
Customers under this Rider Schedule must comply with all OPPD Service Regulations.

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RIDER SCHEDULE NO. 467 & 467H

General Service/Large General Service – Curtailable
(*Currently Unavailable for New Customers*)

APPLICABILITY

This Rider Schedule is applicable to all non-Residential Customers throughout OPPD's Service Area that are capable and willing to curtail a minimum of 100 kilowatts of Curtailable Demand (consisting of a minimum of 20% of Customer Load) or 500 kilowatts (without restrictions) during Curtailment Periods specified by OPPD, subject to the terms of this Rider Schedule and any applicable Curtailment Agreement.

The Customer must agree to reduce the Load served by OPPD during a Curtailment Period, upon request by OPPD, to the Firm Demand. The Customer must enter into a Curtailment Agreement with OPPD, and the decision to enter into a Curtailment Agreement with any Customer under this Rider Schedule is at the discretion of OPPD and is based on operational and market conditions.

This Rider Schedule is not available to those Customer accounts served under Rider Schedule Nos. 355, 464, or 467L.

BILLING COMPONENTS

Monthly Service Charge: $84.70 per month

Curtailment Credit:

Option	467	467H
Minimum Demand	100 kW – 9,999 kW	10,000+ kW
Capacity Curtailment Only (Max. 100 hours per year)	$4.67 per kW	$4.96 per kW

Determination of Firm Demand and Curtailable Demand
For purposes of determining the Firm Demand and Curtailable Demand, before December 1 of each year, OPPD will review the Customer's recent historical Load at the time of OPPD's system peak to determine the Customer's average Load for those hours in which OPPD's Load was within 90% of OPPD's annual system peak. Periods during which the Customer provided a Demand reduction in response to a curtailment request will be excluded from this calculation.

Prior to January 1, the Customer may elect to adjust the Firm Demand amount provided the resulting Curtailable Demand is at least 100 kilowatts (consisting of a minimum of 20% of Customer Load) or 500 kilowatts (without restrictions).

An adjustment will be made to the Curtailable Demand if the annual review of the Customer's historical Load characteristics indicates a smaller amount of Curtailable Load is appropriate. If the annual review indicates that the Customer is unable to provide a minimum of 100 kilowatts of Curtailable Demand (consisting of a minimum of 20% of Customer Load) or 500 kilowatts of Curtailable Demand (without restrictions), the Customer will be notified that service will no longer be provided under this Rider Schedule and any applicable Curtailment Agreement will be terminated.

If Demand history is not available, OPPD will review the operation of the facility with the Customer and determine reasonable Curtailable and Firm Demands.

Non-Compliance Charge for Failure to Reduce Load to the Firm Demand
For a July or August billing period, loss of credit for four (4) times the monthly credit per kilowatt of Curtailable Demand for all Demand exceeding the Firm Demand during any Curtailment Period. For a June or September billing period, loss of credit for two (2) times the monthly credit per kilowatt of Curtailable Demand for all Demand exceeding the Firm Demand during any Curtailment Period.

In the event of multiple failures to reduce Load within the same billing period:

- The loss of credit penalty will be applied once per kilowatt to the Customer's highest Demand recorded for all Demand exceeding the Firm Demand during the billing period; and
- For any monthly billing period, 50 cents per kilowatt-hour for all energy exceeding the Firm Demand level taken during each Curtailment Period.

If a Customer's failure to curtail to the Firm Demand when requested results in an OPPD purchase of capacity, the Customer will also reimburse OPPD for a proportionate share of this capacity cost. This reimbursement will be based on the current levelized cost of a combustion turbine peaking unit, including fixed capital and operation and maintenance costs. This charge will be increased by 23% to recover costs associated with the reserve margin and Demand losses on the transmission and distribution system. The resultant charge will be applied to the Customer's highest Demand recorded for all Demand exceeding the Firm Demand during a Curtailment Period. These charges will be assessed only once during the June 1 through September 15 period.

If the capacity purchase is less than the amount of Load not curtailed by the Customer, a pro-rated share of the capacity charge will be assessed to the Customer.

ADMINISTRATIVE

Definitions

Curtailable Demand: The Demand the Customer agrees to have available for curtailment within a four-hour notification period. The Demand is either at least 100 kilowatts consisting of a minimum of 20% of Customer Load or 500 kilowatts without restrictions. This Load can be curtailed and/or served by the Customer's Emergency Generating Units.

Curtailment Period:
Capacity Curtailment: May only occur when OPPD's projected Load is within 95% of the Deficit Load Condition, as determined by OPPD, or as directed by the Southwest Power Pool (SPP) by the Reliability Coordinator or Balancing Coordinator for OPPD, to reduce Load from June 1 through September 15, 12 P.M. to 10 P.M., Monday through Friday, excluding NERC Holidays. There is a maximum of 100 hours of Capacity Curtailment during a contract year.

Firm Demand: The Demand the Customer agrees not to exceed during a Curtailment Period. The Firm Demand is the Customer's Load that is not subject to curtailment.

Deficit Load Condition: The point at which OPPD's Load exceeds available capability, less net reserve capacity obligation, plus firm purchases, less firm sales.

Duration of Curtailment Period: The Curtailment Period will not exceed ten (10) hours.

Curtailment Notification: The Customer will be notified at least four (4) hours in advance of the time the Customer's Load must be curtailed. OPPD will specify that the Customer must not exceed the Firm Demand level during the Curtailment Period. Notification will be given to the Customer by at least 3 P.M. on the day of a curtailment.

Notice of a Curtailment Period will be by email.

OPPD will also follow-up the email with a telephone call to the Customer's designated official contact. The Customer will provide OPPD with the name, telephone number, and email address of the primary and secondary contacts. The inability of OPPD to reach the primary or secondary contacts by telephone will not relieve the Customer of the obligation of curtailing Load when an email notification is sent by OPPD.

Option to Change Curtailment Agreement
Annually, the Customer may make changes to the Curtailment Agreement, if agreed to by OPPD and incorporated into a new or amended Curtailment Agreement. The Customer must notify OPPD before January 1 to make a change for the following calendar year. If the Customer does not notify OPPD by December 31, the Customer will continue to be subject to the same curtailment for the following calendar year.

Rider Schedule Period
This Rider Schedule Duration is three (3) years. The terms of any Curtailment Agreements hereunder will expire at their expiration dates.

Mandatory Testing
OPPD will, at its discretion, conduct one curtailment test day (maximum 10 hours) per year between June 1 and September 15 for testing and compliance with the Rider Schedule.
The curtailment test day can be requested without regard to the Capacity Curtailment provision that the curtailment may only occur when OPPD's projected Load is within 95 percent of the Deficit Load Condition. The hours tested during the curtailment test day will count toward the maximum hours of Capacity Curtailment during a contract year.

Non-Compliance Charge
If a Customer fails to reduce their Load to the Firm Demand level when requested to do so during more than one billing month during the Rider Schedule Duration, including the curtailment test days, the Customer will be subject to the Non-Compliance Charge and:

- Will be removed from this Rider Schedule, or
- The Curtailable and/or Firm Demand level will be adjusted at the discretion of OPPD, provided the resulting Curtailable Demand is not less than 100 kilowatts (consisting of a minimum of 20% of Customer Load) or 500 kilowatts (without restrictions).

Metering
OPPD will provide the necessary Load profile metering equipment and telephone connection to this equipment to administer this Rider Schedule. OPPD will also provide Demand pulses at the metering location for Customer-Owned Demand metering within the Customer's facility.

Special Conditions
OPPD will not be required to accept a level of Curtailable Demand with a Customer greater than OPPD reasonably believes the Customer is capable of providing.

OPPD retains the discretion to limit total participation and total Curtailable Demand under this Rider Schedule.

If OPPD does not require all of the Customers on this Rider Schedule to curtail during a Capacity Curtailment, the Customers that are requested to curtail will be determined at the sole discretion of OPPD. OPPD will rotate these curtailments among all of the Customers on this Rider Schedule.

Customers will not be able to enter into a Curtailment Agreement under this rider for the current calendar year after January 1.

The terms and conditions of the appropriate standard Rate Schedule applicable to the service rendered form a part of this Rider Schedule.

If the Customer elects to operate Emergency Generating Units in parallel with OPPD rather than curtail Load, the interconnection of this equipment with OPPD's system must meet the standards specified in the policy for "Parallel Operation of Customer-Owned Generation Equipment." All required policies can be found at https://www.oppd.com.

Service Regulations
Customers under this Rider Schedule must comply with all OPPD Service Regulations.

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RIDER SCHEDULE NO. 467E & 467V

General Service – Emergency/Volunteer Curtailable
(*Currently Unavailable for New Customers*)

APPLICABILITY

This Rider Schedule is applicable to all Customers throughout OPPD's Service Area taking service under Rate Schedule Nos. 231, 232, or 245 that may voluntarily curtail a minimum of 100 kilowatts of Demand at one service location when requested by OPPD.

A Customer can only take service under Option E or Option V, not both.

BILLING COMPONENTS

Curtailment Credit Per Event

Option	Amount
467E	$10.25 kW/day
467V	$5.12 kW/day

At the end of each billing period, including a Curtailment Period, OPPD will determine the amount of Curtailed Demand during that month.

ADMINISTRATIVE

Curtailment Period

OPPD has the option of declaring a Curtailment Period, whether Emergency or Voluntary, at OPPD's sole discretion during the period of June 1 through September 15.

The duration of any curtailment will not exceed eight (8) hours per day. Curtailment Periods will only occur from12 P.M. to 10 P.M.

Curtailed Demand

The Demand (a minimum of 100 kilowatts) the Customer agrees to have available for the Curtailment Period when provided with a one-hour notification. This Load can be curtailed and/or served by the Customer's Emergency Generating Units.

OPPD will determine the Customer's Curtailed Demand during each billing period. This will be based on a comparison of the Load that would normally be placed on OPPD's system by the Customer during peak conditions with the Customer's Load observed during the Curtailment Period(s). A review of the Customer's actual Load profiles will be used for this comparison.

Curtailment Notification
Customers will be requested to curtail Demand with not less than one (1) hour notice from OPPD. Curtailment requests are at the sole discretion of OPPD.

OPPD will provide official notification of a curtailment request by email and will follow up on the email notification with a telephone call to the Customer's designated official contact. The Customer will provide OPPD with the name, telephone number, and email address of the Customer's primary and secondary contacts.

The Customer's primary or secondary contacts will indicate acceptance of OPPD's curtailment request by email. This acceptance will be regarded as notification by the Customer of intent to curtail a minimum of 100 kilowatts of Demand for the duration of the Curtailment Period at the price per the applicable Curtailment Credit section of this Rider. The Customer's failure to respond to OPPD's curtailment request before the start of the Curtailment Period will be regarded as an indication by the Customer that they will not curtail.

Schedule Period
This Rider Schedule Duration is one year. The terms of any Curtailment Agreements hereunder will expire at their expiration dates.

Non-Compliance Penalties
Customers failing to curtail a minimum of 100 kilowatts of Demand for the duration of the Curtailment Period after notifying OPPD of their intention to curtail will forfeit any credits and may be removed from the Voluntary Curtailable Rider at the sole discretion of OPPD. For Emergency Curtailable Customers, failure to execute a request to curtail will also be considered non-compliance.

Metering
OPPD will provide the necessary Load profile metering equipment to administer this Rider Schedule.

Special Conditions
The terms and conditions of the appropriate standard Rate Schedule apply to the service rendered and form a part of this Rider Schedule.

If the Customer elects to operate Emergency Generating Units in parallel with OPPD rather than curtail Load, the interconnection of this equipment with OPPD's system must meet the standards specified in the policy for "Parallel Operation of Customer-Owned Generation Equipment." All required policies can be found at https://www.oppd.com.

Service Regulations
Customers under this Rider Schedule must comply with all OPPD Service Regulations.

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RIDER SCHEDULE NO. 467L

General Service – Curtailable – Leased Capacity Option
(*Currently Unavailable for New Customers*)

APPLICABILITY

This Rider Schedule is applicable to all non-Residential Customers throughout OPPD's Service Area that own and operate electric generating facilities that are interconnected with OPPD's distribution facilities, subject to the terms of this Rider Schedule and applicable Leased Capacity Agreement. The Customer's facilities may normally be used to serve part or all of the Customer's electrical Load. The Customer must be capable of providing a minimum of 100 kilowatts to OPPD.

The decision to enter into a Leased Capacity Agreement with any Customer under this Rider Schedule is at the discretion of OPPD based on operational and market conditions. A Customer desiring to provide curtailable capacity to OPPD by utilizing Emergency Generating Units or by reducing Load may be served on Rate Schedule No. 467, but not this Rider Schedule.

This Rider Schedule is not available to those Customer accounts served under Rate Schedule Nos. 355 or 464.

BILLING COMPONENTS

Monthly Credit:

Capacity Credit:

$4.60 per kW of Leased Capacity

Energy Credit:

25.00 cents/kWh

Reimbursement for energy generated is applicable only when requested by OPPD during the current billing period or during the performance of test procedures when requested by OPPD.

ADMINISTRATIVE

Definitions

Leased Capacity: Amount of capacity, in kilowatts, of the Customer's generating facilities made available to OPPD, as agreed to under a Leased Capacity Agreement. This amount will be determined through test procedures, as discussed below. This amount will not exceed the Customer's Billing Demand as defined under the regular Rate Schedule, applicable to the service rendered by OPPD, unless the Customer has Nebraska Power Review Board approval for these generating facilities.

Metering

OPPD will determine whether the Customer's generating facility metering is sufficient to monitor energy production. If it is determined that new and/or additional metering is required, OPPD will provide and install this metering at the Customer's cost.

Duration of Generating Facility Operation
The duration of any requested generating facility operation will be for a minimum of four (4) hours and a maximum of ten (10) hours, unless otherwise mutually agreed. These requests will occur year-round from 12 P.M. to 10 P.M., Monday through Friday, excluding NERC Holidays.

Curtailment Notification
The Customer will be notified at least four (4) hours in advance of the time the Customer must operate its generating facility. Notification will be given to the Customer by at least 3 P.M. on the day of a request to operate.

Notice of a request to operate will be by email.

OPPD will also follow-up the email with a telephone call to the Customer's designated telephone contact. The Customer will provide OPPD with the name, telephone number, and email address of the primary and secondary contact. The inability of OPPD to reach the primary or secondary contact by telephone will not relieve the Customer of the obligation of operating the Leased Capacity when an email notification is sent by OPPD.

Rider Schedule Period
This Rider Schedule Duration is three (3) years. The terms of any Curtailment Agreements hereunder will expire at their expiration dates.

Test Procedures
The tests to determine the Leased Capacity will be conducted jointly by OPPD and the Customer. The tests will be performed periodically at the request of either the Customer or OPPD and will be one-hour tests. The Customer will provide the personnel and equipment to perform the tests, and the Customer will record and document the tests. If a change in Leased Capacity is indicated it will be revised accordingly on the first day of the subsequent billing period, and the Customer and OPPD either will enter into a new Leased Capacity Agreement or amend the existing Agreement.

Increase in Leased Capacity
The Customer may install or enlarge its generating facilities, and subject to the approval of OPPD, add to the Leased Capacity made available to OPPD. OPPD will recognize the Leased Capacity as determined by the test procedures specified above, and the Customer and OPPD either will enter into a new Leased Capacity Agreement or amend the existing Agreement.

Non-Compliance Actions
If all, or part, of the Leased Capacity is not available to OPPD during any month, OPPD will have the right to suspend credit for that part of the Leased Capacity which is not available for that month or any subsequent month(s). Upon Customer's demonstration in accordance with the test procedures that all or part of the previously unavailable Leased Capacity is available, OPPD will resume the monthly credit for this capacity during the following month.

Absent this demonstration, OPPD may reduce the amount of Leased Capacity for the remainder of the term of the Leased Capacity Agreement.

In the event all or part of the Leased Capacity, excluding any scheduled maintenance, is not available when OPPD requests that power be generated, OPPD will provide written notice to the Customer of this non-compliance. If two of these notices are sent to the Customer in a two year period, OPPD will have the right to reduce the amount of the Leased Capacity for the remainder of the term of the applicable Leased Capacity Agreement. OPPD will provide the Customer with not less than fifteen (15) days written notice before exercising this right.

Scheduled Maintenance
The Customer will not schedule maintenance of the generating facilities between June 1 and September 15 of any calendar year. The Customer will provide 60-day prior notice of any scheduled maintenance to OPPD. The unavailability of generating facilities for scheduled maintenance will not exceed thirty (30) days.

Special Conditions
OPPD retains the right at its sole discretion to limit participation and the total amount of Leased Capacity it purchases through this Rider Schedule.

The terms and conditions of the appropriate standard Rate Schedule applicable to the service rendered form a part of this Rider Schedule.

Service Regulations
Customers under this Rider Schedule must comply with all OPPD Service Regulations.

Return to Rates and Riders List

RIDER SCHEDULE NO. 469 & 469S

General Service – Time-of-Use

APPLICABILITY

This Rider Schedule is applicable to all Customers throughout OPPD's Service Area taking service under Rate Schedule Nos. 231, 232, or 245.

This Rider Schedule cannot be combined with Rider Schedule Nos. 464, 467, or 467L.

Option 469S is not available to Customers with a Billing Demand exceeding 150 kilowatts.

BILLING COMPONENTS

Monthly Rate: $56.40

Determination of Billing Demand
The Billing Demand for the applicable Rate Schedule will be adjusted as specified by the Determination of Billing Demand section of this Rider Schedule.

For the summer months, defined as the billing months of June through September 15, will be the greater of:

- The highest On-Peak Demand during the current month or the preceding eleven (11) months, or
- 33% of the highest Off-Peak Demand of the current month, or
- The Demand minimum of the applicable Rate Schedule.

For the non-summer months, defined as the billing months of September 16 through May, will be the greater of:

- The highest On-Peak Demand occurring during the preceding June through September 15 time period, or
- 33% of the highest Off-Peak Demand of the current month or preceding 11 months, or
- The Demand minimum of the applicable Rate Schedule.

If the Demand is less than 85% of the Customer's highest 15-minute kilovolt ampere Demand, OPPD will increase the Demand under this Schedule by 50% of the difference between 85% of the kilovolt ampere Demand and the Demand as determined above.

ADMINISTRATIVE

Definitions

On-Peak Demand: The kilowatts of Demand as determined from OPPD's Meter for the 15-minute interval of the Customer's highest use during the billing period. The On-Peak Demand is set only between the hours of 12 Noon and 10:00 PM, Monday through Friday, from June to September, excluding Federal Holidays.

Option 469S – On-Peak Demand: The kilowatts of Demand as determined from OPPD's Meter for the 15-minute interval of the Customer's highest use during the billing period. The On-Peak Demand is set only between the hours of 2:00 PM and 7:00 PM, Monday through Friday, from June to September, excluding Federal Holidays.

Off-Peak Demand: The kilowatts of Demand as determined from OPPD's Meter for the 15- minute interval of the Customer's highest use during the Off-Peak hours of the billing period. The Off-Peak hours are defined as all hours of the year not defined as on-peak hours.

Special Conditions

OPPD reserves the right to limit total participation and total On-Peak Demand on this Rate Schedule.

Customers taking service on this Rider Schedule are not eligible to be on OPPD's level payment plan.

For a Customer requesting to start on this Rider Schedule during an Off-Peak billing period, October to May, without a previously established On-Peak Demand, the Billing Demand will be determined by OPPD until such time that an actual On-Peak Demand is established. Once an actual On-Peak Demand has been established, the criteria defined in the determination of Billing Demand will apply.

Option 469S: Any Customer that exceeds an On-Peak Demand of 150 kilowatts or an Off-Peak Demand of 457 kilowatts during two billing periods within a twelve (12) month period will not be eligible for this Rider Schedule and will not be able to take service under this Rider Schedule again for a period of twelve (12) months. At the end of the twelve (12) months and OPPD's discretion, if OPPD's annual review of the historical Load indicates the Customer can maintain a maximum Billing Demand of no greater than 150 kilowatts, the Customer may be allowed take service under this Rider Schedule.

Service Regulations

Customers under this Rider Schedule must comply with all OPPD Service Regulations.

Return to Rates and Riders List

SCHEDULE NO. 470

General – Customer Service Charges

APPLICABILITY

This Rider Schedule is applicable to all Customers, Contractors, and Developers for miscellaneous service operations.

BILLING COMPONENTS

Rates:

(470A): Activation Fee

Non-landlords	$ 22.50
Landlords	$ 15.00

(470B): Reconnect Service after Delinquent Bill Disconnect	$ 75.00
(470C): Disconnect following Unauthorized Reconnect – Each Occurrence	$175.00
(470D): Field Collection Call – No Disconnect	$ 30.00
(470E): Returned Payment Fee	$ 30.00

(470F): Line Extension Charges (Residential)

Underground service to new apartment complexes will be charged the standard, per unit development rate ~~$30.00 per dwelling unit~~. All conduit and pull boxes are to be installed by the Customer.

200 Amp, 120/240 volt, 3-wire
-underground service in overhead areas will be billed at
$1,500.00~~$1,050.00~~ each. The Customer is required to install a secondary conduit from the overhead service pole or pedestal to the Meter.

320 Amp, 120/240 volt, 3-wire underground service in overhead areas will be billed at $1,500.00~~$1,050.00~~ each. The Customer is required to install a secondary conduit from the overhead service pole or pedestal to the Meter.

Costs for underground dips exceeding 320 Amperes will be based on actual costs, plus overheads.

There is no charge to extend underground service to the closest Point of Entrance in Residential developments. Extensions beyond that point will be billed at $15.00~~8.25~~ per foot.

Underground service to new subdivisions of normal configuration where such lot is less than one acre will be charged or reimbursed at ~~$540~~ the standard, per lot development rate~~per lot~~. The Customer is required to design, procure, and install all primary and secondary conduits, pull boxes, transformer basements and pedestals to OPPD's standards and specifications. Effective, January 1, 2017, all underground services to new subdivision lots of normal configuration, where such lot is less than one acre and signed under an Underground Service Agreement before December 31, 2013, the Customer is required to install secondary conduit from OPPD service pedestal stub-out to the Meter.

Underground service to new subdivisions of normal configuration where such lot is greater than one acre will be charged the standard, per-lot development rate plus the cost differential of overhead to underground per foot of cable installed.

The charge for temporary single-phase overhead service will be $500.00~~$326.00~~, including the activation fee.

The charge for temporary single-phase underground service will be $200~~$130.00~~, including the activation fee.

Rerouting an existing underground service to accommodate homeowner property changes will be charged at $25.00~~$19.62~~ per foot, with a $200 minimum charge.

(470G): Farm Transfer Switch Charges to be Actual Cost Plus Overhead (ACPO)

200 Amp Transfer Switch – ACPO

400 Amp Transfer Switch – ACPO

(470H): Line Extensions and Temporary Service Disconnects Charges (General Service)

~~The underground~~ Underground service ~~charge~~ for 200 Amp Loop within any new commercial or industrial developments for a primary backbone will be charged the standard, per-acre development rate. ~~is $4,060.00 per acre~~.

~~The underground~~ Underground service ~~charge~~ for 200 Amp Loop within any new commercial or industrial developments for a primary backbone where the developer ~~customer~~ has designed, procured, and installed all facilities necessary to provide a path for OPPD to install primary cables and switches between sources will be charged the standard, per-lot development rate. ~~is $1,620.00 per acre.~~

The underground service charge for 600 Amp Loop within any new commercial or industrial developments for a primary backbone will be charged based on the estimated difference between underground costs vs. overhead costs.

200 Amp – All standard voltages, commercial underground dip for single-phase service will be billed at $1,500~~$2,500.00~~ each.

320 Amp – All standard voltages, commercial underground dip for single-phase service will be billed at $1,500~~$2,500.00~~ each.

All three-phase underground commercial dips will be charged based on the estimated difference between underground costs vs. overhead costs.

The charge for temporary single-phase overhead service will be $500~~$350.00~~, including the activation fee.

The charge for temporary single-phase underground service will be $200~~$250.00~~, including the activation fee.

The charges for temporary service disconnects at the Customer's request will be as follows:

Guaranteed Start Time:

$295.00 per hour on Saturdays.

$430.00 per hour after 3:00 P.M. and before 7:00 A.M. on Monday through Friday.

$565.00 per hour on Sundays and OPPD designated holidays: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and the day after Thanksgiving, Christmas Eve and Christmas Day or the days these holidays are observed by OPPD.

There is no charge during all remaining hours.

(470I): The Tenant Attachment Fee

The annual tenant attachment fee for joint use of OPPD's poles is $19.00~~18.00~~ per attachment.

(470K): Miscellaneous Charges

Many of OPPD's Customer service charges are based on actual expenses incurred by OPPD. Examples of these charges include raising power lines for house moves, service reroutes, temporary relocations of systems during construction, emergency repairs of Customer-Owned equipment and, at OPPD's discretion, information requests that require extensive research. All of these charges will be billed at the utility's costs plus overhead.

(470L): Overhead Costs

All charges that are based on actual costs will include the current transmission and distribution overhead rate.

(470M): Monthly Meter Reading and Access Charge

The charge for meter reading for Customers who have an inaccessible meter, deny access or elect to utilize meters that do not have two-way communications capability is $50.00 per meter per month .

(470N): Non-AMI Meter Installation Charge

The installation charge for meters for customers not utilizing meters that have two-way communications capability is $220.00 per installation.

ADMINISTRATIVE

Service Regulations

Customers under this Rider Schedule must comply with all OPPD Service Regulations.

Return to Rates and Riders List

RIDER SCHEDULE NO. 483

Net Metering Service

APPLICABILITY

This Rider Schedule is applicable to all Customers in OPPD's Service Area with a Qualified Generator not taking service for the same Qualified Generator under Rider Schedule No. 355. This Rider Schedule is also not available to Customers taking service under Rate Schedule No. 357 – Municipal Service. Energy Storage systems capable of storing OPPD-supplied energy and exports that energy back to OPPD's system do not qualify.

DG Systems qualifying for Rider Schedule No. 483 shall not exceed 100kW in the aggregate system AC nameplate capacity, as determined by OPPD during the DG application and approval process.

BILLING COMPONENTS

Net Excess Generation Credit:

Excess Generation	Summer (June 1 – Sept. 30)	Non-Summer (Oct. 1 – May 31)
Per kWh	4.00 cents/kWh	3.52 cents/kWh

Determination of Customer Bill

The Customer can use Qualified Generator electrical output to supply all or a portion of the Customer's Demand and deliver the surplus to OPPD. At the end of the billing period, the net flow of the energy between the Customer and OPPD will be calculated, and the Customer's bill will be based on the net energy flow as follows:

- *Net flow from OPPD to the Customer:* The Customer will be billed for the net use at the monthly rate and based on the provisions included in the Customer's applicable Rate Schedule.
- *Net flow from the Customer to OPPD:* The Customer will be billed for the non-energy charges based on the provisions included in the Customer's applicable Rate Schedule and will receive a bill credit for the Net Excess Generation. If the bill credit is greater than the current month's billing, the Customer will carry an account credit balance for use in future months. At the end of the calendar year, any excess bill credits associated with Net Excess Generation will be paid to the Customer.

ADMINISTRATIVE

Definitions

Net Excess Generation: Production of more electrical energy than is consumed by the Customer during a billing period.

Special Conditions

Customers are responsible for Qualified Generator equipment and services required for interconnection. If desired, Customers are responsible for metering to measure the energy produced by the Customer's Qualified Generator. The Customer will maintain ownership of renewable energy credits associated with a Qualified Generator.

Customers taking service on this Rider Schedule are not eligible for OPPD's Level Payment Plan.

OPPD will provide, at no additional cost to the Customer, metering that is capable of measuring the flow of electricity in both directions. This equipment may be a single bidirectional Meter, smart Meter, two Meters, or another Meter configuration that provides the necessary information for service under this Rider Schedule.

Service Regulations
Customers under this Rider Schedule must comply with all OPPD Service Regulations.

Return to Rates and Riders List

RIDER SCHEDULE NO. 484

Supplemental Distribution Capacity

APPLICABILITY

This Rider Schedule is applicable to all Customers throughout OPPD's Service Area taking service under Rate Schedule Nos. 231, 232, 245 or 357.

BILLING COMPONENTS

A monthly charge based on the style of switch required to serve the Customer's Load:

Switch Style Charge*	Amount
PMH style ATO	$665.00
Upright Gear Non-Split Bus	$645.00
Upright Gear Split Bus-2 Sources	$1,885.00

**If applicable, this can be divided among multiple Customers. Please refer to Special Conditions for more information.*

Distribution System Capacity Charge of $1.41 per kilowatt of Demand

Demand will be determined from the "Determination of Demand" section of the applicable Rate Schedule.

OPPD will adjust the Demand when OPPD is requested to provide an additional source(s) of distribution capacity for partial Customer Load.

Minimum Monthly Bill

The Minimum Bill from the regular Rate Schedule applicable to the service rendered, plus the charges for the ATO Switch Charge and the Distribution System Capacity Charge, as applicable.

ADMINISTRATIVE

Rider Schedule Period

This agreement remains in place five years, with automatic renewal for additional one-year periods, as long as OPPD continues to provide the service as requested by the Customer under this Rider Schedule.

Service Provided

The Customer may request OPPD to provide an additional source(s) of distribution capacity to serve all or part of the Customer's Load as a contingency service when the normal distribution capacity is unavailable. OPPD may provide a manual throw-over switch for this service, or OPPD will provide an automatic throw-over (ATO) switch if the Customer requests the ATO. The ATO Switch Charge will not apply if a manual throw-over switch is provided.

Such additional source(s) of distribution capacity will be provided at OPPD's sole discretion if practical and safe, as determined by OPPD. Such service will not be provided if it would create an unusual hazard or interfere with the service provided to other Customers.

Disconnect Charge
Termination of service by a Customer at any time within the initial period under this Rider Schedule will not suspend or eliminate the ATO Switch Charge or the Distribution System Capacity Charge, specified above, for the months for which this service is terminated and will be applied to the final bill.

Special Conditions
All ATO switches for Customers will be supplied, installed, and maintained by OPPD.

If an ATO switch serves more than one Customer that has requested such service, the ATO Switch Charge will be divided equally among the Customers based on the number of Customers receiving such service. This calculation will be adjusted monthly if existing Customers discontinue service or if new Customers initiate service through this ATO switch.

Any investment required to connect the switch to the alternative distribution capacity source will be charged in accordance with OPPD's internal policies, including investments for new connections or upgrades to existing connections.

Service Regulations
Customers under this Rider Schedule must comply with all OPPD Service Regulations.

Return to Rates and Riders List

RIDER SCHEDULE NO. 500

Community Solar

APPLICAIBLITY

This Rider Schedule is applicable to all Customers throughout OPPD's Service Area taking service under any Retail Rate Schedule.

BILLING COMPONENTS

Refundable Enrollment Deposit:

Residential Customers on Rate Schedules 110, 115, and 120 will be charged a $100 refundable enrollment deposit to begin participation under this rate Rider Schedule. All other Customer rates will be assessed a refundable enrollment deposit based on the greater of $100 or a combination of the average usage of the rate class and the Community Solar subscription level as agreed upon in the Community Solar Service Agreement.

OPPD will refund this deposit if the Customer participates in this rate Rider Schedule for:

- Five (5) consecutive years for Rate Schedules 110, 115, and 120
- Ten (10) consecutive years for Rate Schedules 226, 230, and 231
- Twenty (20) consecutive years for Rate Schedules 232, 245 and 261M

If a Customer elects to end participation under this rate Rider Schedule before the above requirements, the refundable enrollment deposit will be forfeited.

Community Solar Charge:

Community Solar Charge = Market Based Value of Solar * Subscription Level

ADMINISTRATIVE

Definitions

Subscription Level: Quantity of Community Solar Share(s).

Community Solar Share: 100 kWh per month.

Market-Based Value of Solar: Calculated on a per-share cost and is defined as the interconnected cost of the community solar Purchased Power Agreement (PPA), less the actual hourly community solar production from the prior year valued at the corresponding Southwest Power Pool (SPP) day-ahead hourly prices, less the accredited capacity assigned by SPP to the community solar facility(s) valued at the annual levelized value of OPPD's next marginal generation capacity.

Special Conditions

Service under this Rider will be limited to the aggregate amount of generation available by all community solar PPAs.

The Community Solar Service Agreement may be revised periodically by OPPD.

The Community Solar kWh Charge will be updated annually, as stated in the Community Solar Service Agreement.

Service Regulations
Customers under this Rider Schedule must comply with all OPPD Service Regulations.

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Omaha Public Power District
BOARD OF DIRECTORS

Reporting Item

November 17, 2026

ITEM

Third Quarter 2026 Financial Report

PURPOSE

Report the quarterly financial results to the Board of Directors

FACTS

a. The third quarter 2026 financial results are attached for review.

b. Retail Revenue for the third quarter 2026 was $533.8 million, which was $49.2 million over budget. Off-system Revenue was $110.1 million, which was $57.4 million over budget. Other Income was $77.7 million, which was $34.6 million over budget.

c. Operations and Maintenance Expense (less Fuel and Purchased Power) for the third quarter 2026 was $181.3 million, which was $34.4 million over budget. Fuel and Purchased Power Expense was $260.7 million, which was $83.0 million over budget. Other Expense was $124.9 million, which was $14.4 million over budget.

d. Operating Income for the third quarter 2026 was $166.1 million, which was $4.6 million under budget.

e. Net Income for the third quarter 2026 was $154.8 million, which was $9.4 million over budget.

RECOMMENDED:

DocuSigned by:
Bradley Underwood
D70A0027FE154F8...

Bradley R. Underwood
Vice President and Chief Financial Officer

APPROVED FOR REPORTING TO BOARD:

Signed by:
L. Javier Fernandez
AC399FDCE502475...

L. Javier Fernandez
President and Chief Executive Officer

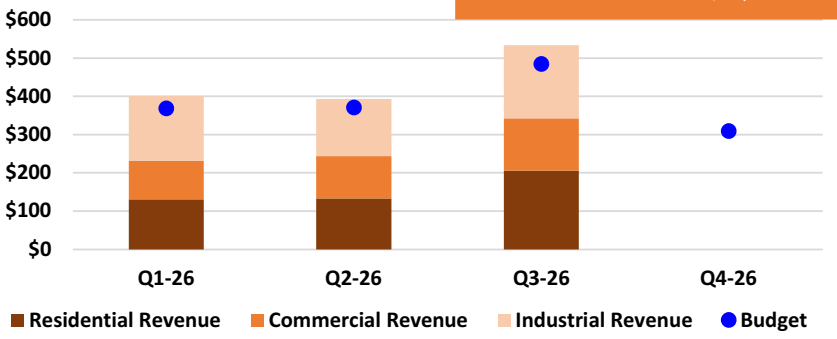
Attachment: Quarterly Financial Report (Graphs)

Q3 2026 Results ($ Millions)

Your Energy Partner
OPPD
Omaha Public Power District

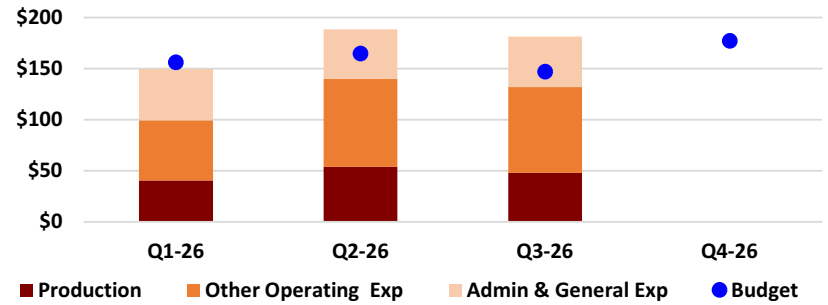
Retail Revenue

YTD ACTUALS 2026 - $ 1,327.3
YTD BUDGET 2026 - $ 1,223.8



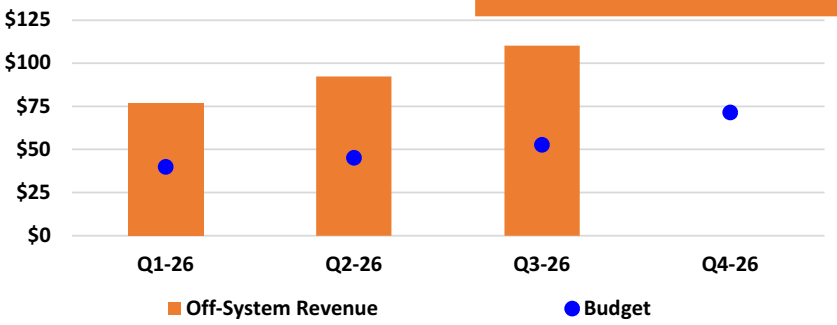
O&M Expense (less Fuel & Purchased Power)

YTD ACTUALS 2026 - $ 518.9
YTD BUDGET 2026 - $ 467.7



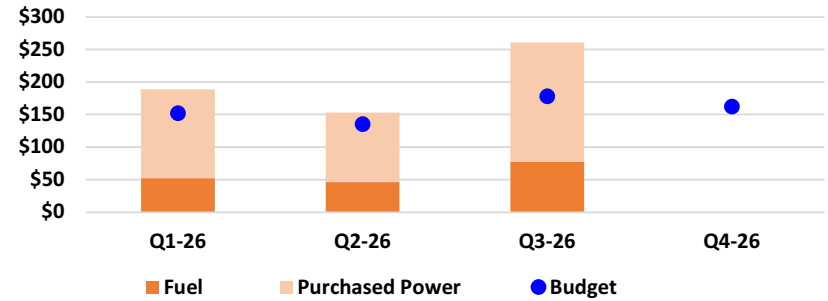
Off-System Revenue

YTD ACTUALS 2026 - $ 279.4
YTD BUDGET 2026 - $ 137.6



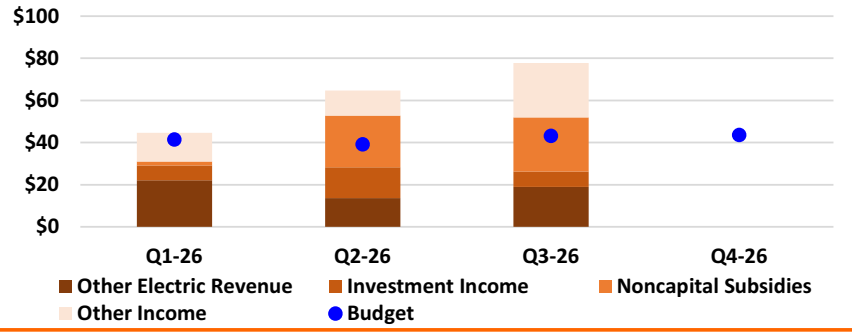
Fuel & Purchased Power

YTD ACTUALS 2026 - $ 602.3
YTD BUDGET 2026 - $ 465.2



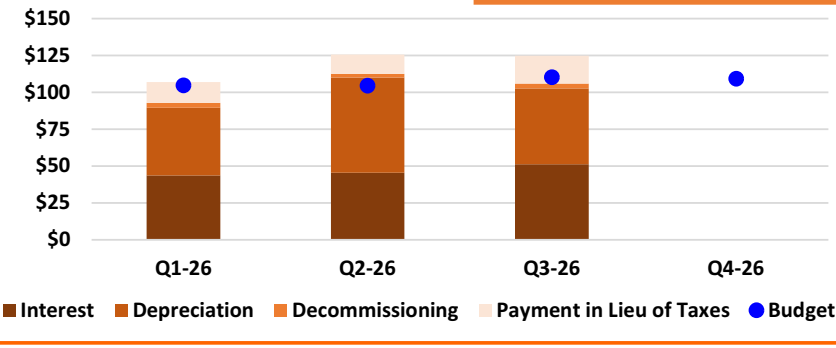
Other Income

YTD ACTUALS 2026 - $ 187.0
YTD BUDGET 2026 - $ 123.6



Other Expense

YTD ACTUALS 2026 - $ 357.4
YTD BUDGET 2026 - $ 320.1



◇ - Favorable ◆ - Unfavorable

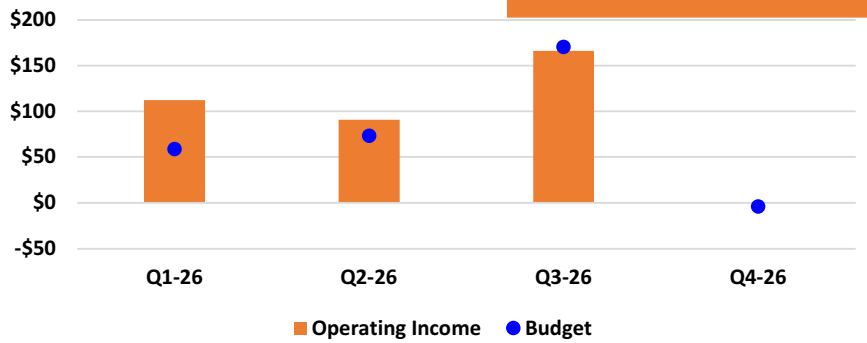
Unaudited results.

Q3 2026 Results ($ Millions)

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Omaha Public Power District

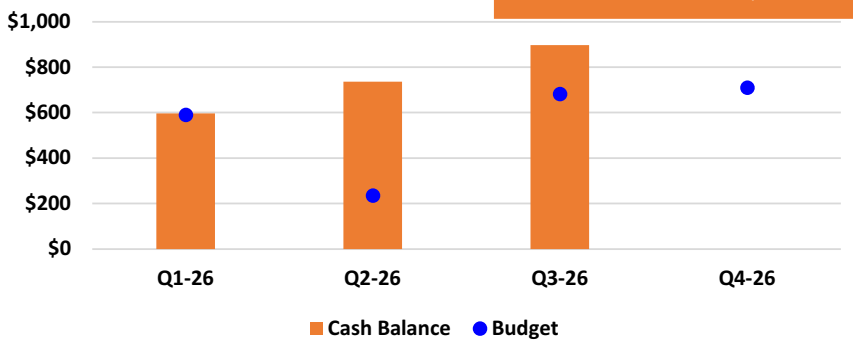
Operating Income

YTD ACTUALS 2026 - $ 369.1
YTD BUDGET 2026 - $ 303.4



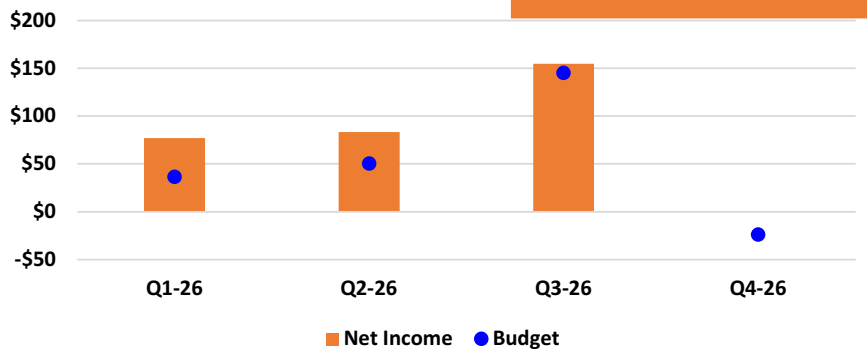
Cash Balance

YTD ACTUALS 2026 - $ 896.1
YTD BUDGET 2026 - $ 681.0



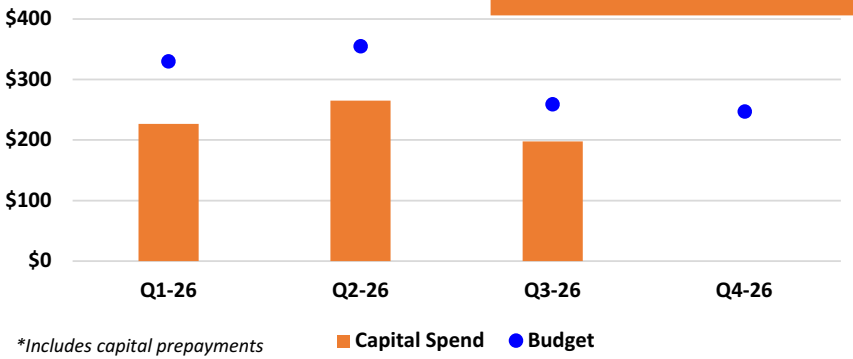
Net Income

YTD ACTUALS 2026 - $ 315.1
YTD BUDGET 2026 - $ 232.1



Capital Spend*

YTD ACTUALS 2026 - $ 689.0
YTD BUDGET 2026 - $ 943.2



SD Impact:

* **SD-2 Rates** -
OPPD's 2024 average retail rate was 14.1% below the West North Central region based on 2024 data from the Energy Information Administration (EIA).

* **SD-3 Access to Credit Markets** -
The 12-month rolling debt service coverage ratio is 2.77 times through September 2026, and is forcasted at 2.0 times at year-end. The District's days of cash on hand is 258 days as of September 30, 2026.

HIGHLIGHTS:

* Retail revenues were over budget YTD by $103.5 million, or 8.5%, primarily due to higher usage across all customer classes. Off-system sales were over budget YTD by $141.8 million, or 103.0%, primarily due to higher than expected congestion hedging revenues. Other income was over budget by $63.4 million, or 51.3%, primarily due to the recognition of revenue from FEMA for damages from the 2024 and 2025 storms and higher than expected renewable energy credit sales.
* O&M expense (less fuel and purchased power) was over budget YTD by $51.2 million, or 10.9%, primarily due to higher distribution expense as a result of the recognition of expense from the 2024 and 2025 storms as a result of FEMA's obligation of the storm projects. Fuel and purchased power expense was over budget YTD by $137.1 million, or 29.5%, primarily due to increased market prices particularly during winter storm Fern and higher purchase volumes. Other expenses were over budget YTD by $37.3 million, or 11.7%, primarily due to higher interest expense from outstanding debt.
* Operating income of $369.1 million YTD was over budget by $65.7 million and Net Income of $315.1 million YTD was over budget by $83.0 million due to the operating results addressed above.
* Capital expenditures were under plan YTD by $254.2 million, or 27.0%, primarily due to timing delays on project execution. Cash balances increased due to restricted construction fund assets becoming unrestricted cash during the quarter and the timing of investment transactions.

◇ - Favorable ◆ - Unfavorable

Unaudited results.

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Omaha Public Power District

BOARD OF DIRECTORS

Reporting Item

November 17, 2026

ITEM

Retirement Plan – Third Quarter 2026

PURPOSE

To Report the Retirement Plan Fund's Third Quarter 2026 Performance Results

FACTS

a. The Retirement Plan Fund market value at the end of the third quarter was $1.47 billion. This compares to the market value at the beginning of the quarter of $1.50 billion. During the quarter, employee contributions were $6.40 million, and OPPD contributions totaled $17.41 million. Benefit payments totaled $30.01 million, and the investment market value decreased (net of expenses) by $23.8 million.

b. As of September 30, 2026, the Retirement Fund asset allocation was 58.3% Equity, 27.8% Fixed Income and 13.9% Alternative Assets, which is within the Investment Policy Guidelines approved by the Board.

c. The Retirement Plan Fund sector performance (net of fees) was:

Sector	Market Value	Quarterly Return	Index
Domestic Equity	$456,172,761	-1.8%	-1.4%
International Equity	$401,238,005	1.1%	0.7%
Domestic Fixed Income	$346,430,822	-3.2%	-3.3%
Global Fixed Income	$63,419,063	-4.3%	-4.0%
Private Real Estate	$93,523,029	0.5%	1.8%
Private Credit(1)	$111,874,758	1.8%	—
Total	**$1,472,658,438**	**-1.5%**	**-1.4%**

(1) Quarterly internal rate of return as of 3-31-2026 (return data not available for most recent quarter).

d. The Domestic Equity Composite declined 1.8%. Large cap led mid and small cap on a relative basis and value led growth across the size spectrum. The International Equity Composite increased 1.1% fueled primarily by Japanese returns and positive currency conversions.

e. The Domestic Fixed Income Composite declined 3.2% as yields climbed to levels not seen since 2002. The 10-year treasury yield rose 28 basis points. The US Federal Reserve Open Market Committee voted to increase the federal funds rate by 25 basis points in September. The Global Fixed Income Composite declined by a sharp 4.3%.

f. The Real Estate Composite returned 0.5%, continuing a gradual US commercial market recovery. Income was the primary driver of returns. Office fundamentals continued an improving trend including positive net absorption, declining vacancies and construction completions at record lows.

RECOMMENDED: APPROVED FOR REPORTING TO BOARD:

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DocuSigned by:
Bradley Underwood
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Bradley R. Underwood
Vice President and Chief Financial Officer

Signed by:
L. Javier Fernandez
AC399FDCE56247E...

L. Javier Fernandez
President and Chief Executive Officer

BRU: jap

Attachments: Summary of OPPD Retirement Plan Assets
OPPD Retirement Plan Total Assets – Annual Market Valuation Graph
OPPD Retirement Plan Total Assets – Quarterly Market Valuation Graph

SUMMARY OF OPPD RETIREMENT PLAN ASSETS
AS OF SEPTEMBER 30, 2026

Manager Valuations, Distributions and Returns(*)

		FUND TYPE	TOTAL VALUATION	PERCENT OF FUND	NET OF FEES RETURNS QUARTERLY	NET OF FEES RETURNS YEAR-TO-DATE	DIFFERENCE ABOVE/(BELOW) YTD INDEX
EQUITY MANAGERS:							
Domestic Large Capitalization							
	State Street Global Advisors Russell 1000	Index/Core Equity	**284,219,394.00**	19.3%	1.8%	12.3%	0.0%
Domestic Middle Capitalization							
	Kayne Anderson Rudnick(1)	Core/Growth	74,407,407.00	5.0%	-5.5%	-4.5%	-14.4%
Domestic Small Capitalization							
	LSV Asset Management	Small Capitalization Value	51,040,052.00	3.5%	-2.5%	15.3%	-1.7%
	Frontier Capital Management	Small Capitalization Growth	46,505,908.00	3.2%	-14.2%	8.2%	-2.5%
International							
	Global Apha Fund	Small Cap. International	51,329,598.00	3.5%	1.1%	1.0%	-9.8%
	MFS International Equity	International Equity	142,296,252.00	9.7%	1.7%	5.1%	-5.2%
	Acadian Emerging Markets(1)	Emerging Markets	207,612,155.00	14.1%	0.7%	31.0%	7.6%
Subtotal Equity			**$ 857,410,766.00**	**58.3%**			
FIXED INCOME MANAGERS:							
Domestic Bonds							
	JP Morgan Investment Management	Investment Grade/Core	79,827,099.00	5.4%	-3.5%	-2.9%	0.0%
	Mackay Shields	Investment Grade/Core	45,974,026.00	3.1%	-1.7%	0.1%	-0.2%
	Reams Asset Management Company	Investment Grade/Core	83,500,275.00	5.7%	-4.0%	-3.0%	-0.1%
	State Street Global Advisors - Bond Market Index	Investment Grade Index/Core	91,220,897.00	6.2%	-3.5%	-2.8%	0.1%
	State Street Global Advisors - TIPS Index	Investment Grade Index/TIPS	29,647,896.00	2.0%	-3.2%	-2.0%	0.1%
International Bonds							
	Stone Harbor Investment Partners L.P.	Emerging Markets	63,419,063.00	4.3%	-4.3%	0.2%	1.4%
Cash							
	Trustee Cash Management Account	Cash & Cash Equivalents	16,260,629.00	1.1%	0.8%	2.4%	-0.2%
Subtotal Fixed Income			**$ 409,849,885.00**	**27.8%**			
ALTERNATIVE ASSETS MANAGERS							
	Private Equity Cash	Private Equity Cash	1,863,098.00	0.1%	NA	NA	NA
	Harrison Street Real Estate Capital	Private Real Estate	48,907,547.00	3.3%	0.3%	2.2%	-2.3%
	PGIM Real Estate	Private Real Estate	44,615,482.00	3.0%	0.7%	3.5%	-1.0%
	Corbin II(2)	Private Credit(1)	21,060,933.00	1.4%	NA	NA	NA
	Corbin III(2)	Private Credit(1)	4,066,048.00	0.3%	NA	NA	NA
	Neuberger Berman IV(2)	Private Credit(1)	67,334,390.00	4.6%	NA	NA	NA
	Neuberger Berman V(2)	Private Credit(1)	17,550,289.00	1.2%	NA	NA	NA
Subtotal Alternative Assets			**$ 205,397,787.00**	**13.9%**			
TOTAL			**$ 1,472,658,438.00**	**100.0%**	-1.5%	6.2%	-0.4%

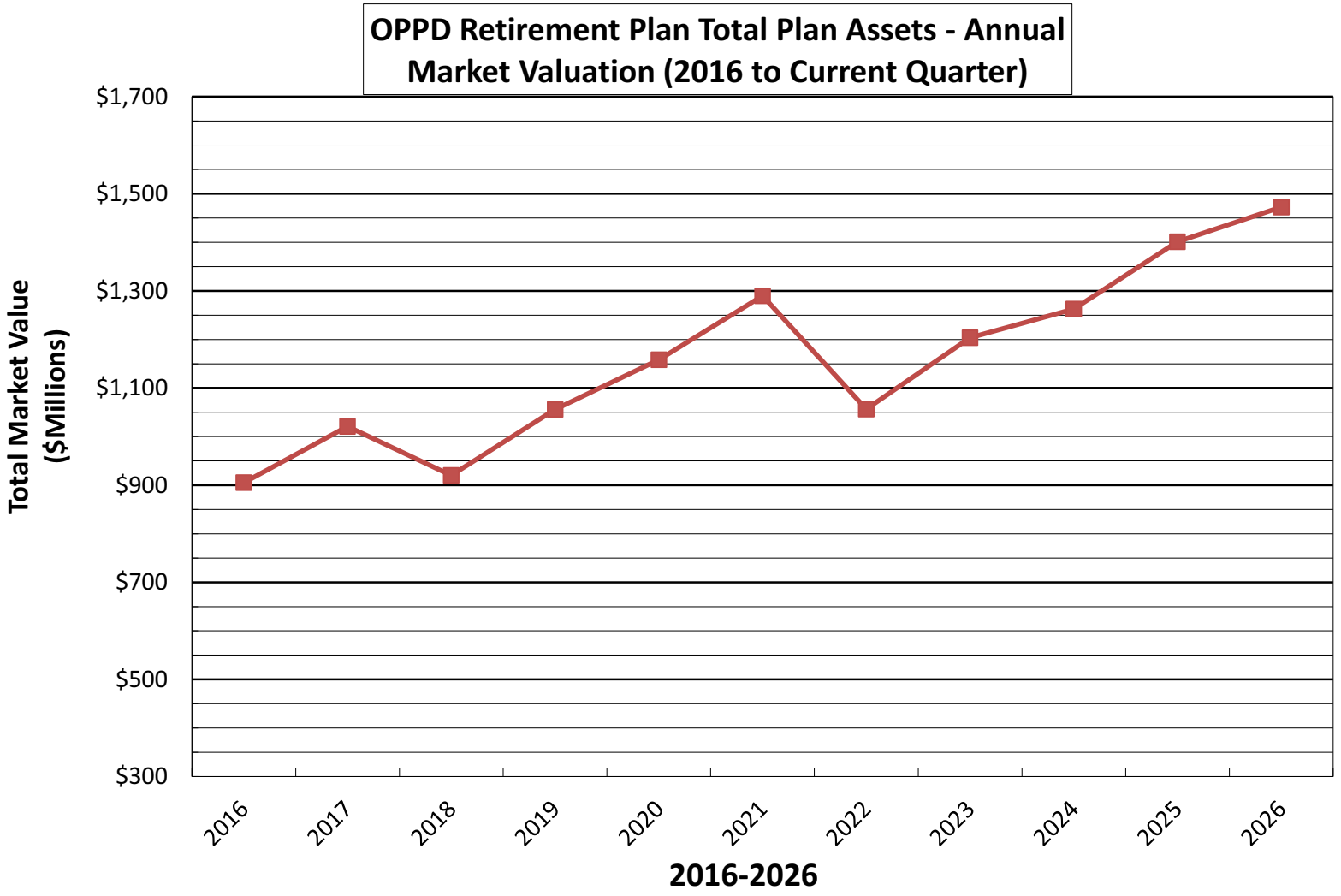
Asset Allocation

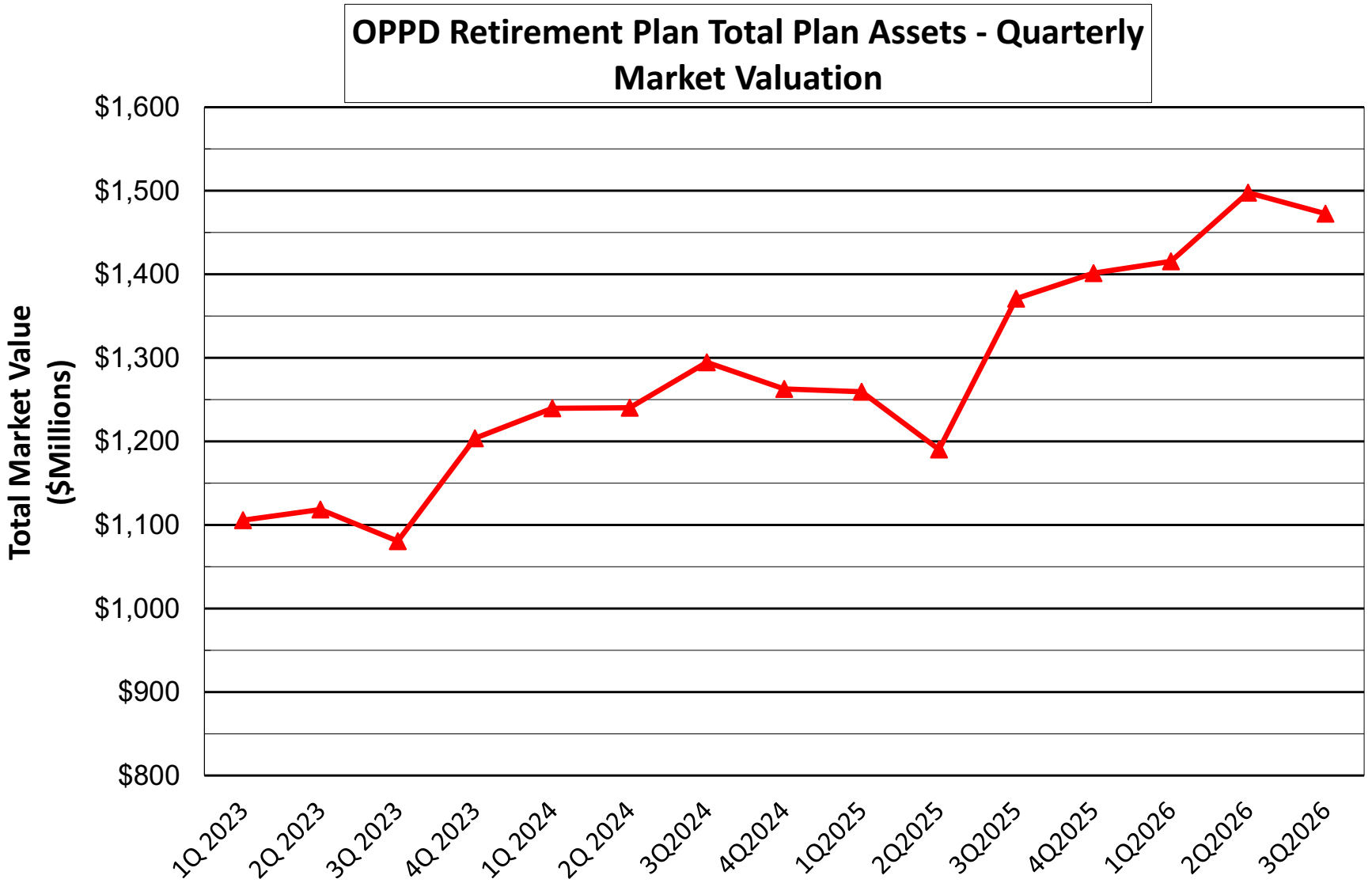
EQUITY ALLOCATION	$ 857,410,766.00	58.3%
FIXED INCOME ALLOCATION	$ 409,849,885.00	27.8%
ALTERNATIVE ASSETS ALLOCATION	$ 205,397,787.00	13.9%
	$ 1,472,658,438.00	**100.0%**

* *Preliminary Data as of this report.*

(1) *Private Credit Managers have not reported 6-30-2026 return data as of this reporting.*

(2) *Multiple Neuberger Berman and Corbin Funds are being used to maintain asset allocation targets.*


OPPD Retirement Plan Total Plan Assets - Annual Market Valuation (2016 to Current Quarter)
Total Market Value ($Millions)
$1,700
$1,500
$1,300
$1,100
$900
$700
$500
$300
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2016-2026


OPPD Retirement Plan Total Plan Assets - Quarterly Market Valuation
Total Market Value ($Millions)
$1,600
$1,500
$1,400
$1,300
$1,200
$1,100
$1,000
$900
$800
1Q 2023
2Q 2023
3Q 2023
4Q 2023
1Q 2024
2Q 2024
3Q2024
4Q2024
1Q2025
2Q2025
3Q2025
4Q2025
1Q2026
2Q2026
3Q2026

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Omaha Public Power District

BOARD OF DIRECTORS

Action Item

November 17, 2026

ITEM
Updated Statement of Investment Policy for the OPPD Retirement Plan

PURPOSE
To approve an updated Statement of Investment Policy for the OPPD Retirement Plan

FACTS

a. The District retained Segal Marco Advisors, the District's Retirement Plan Investment Consultant, to perform an Asset/Liability Study ("Study") for the Retirement Plan ("Plan"). The purpose of the Study was to evaluate the Plan's asset allocation in the context of its liabilities to determine if asset allocation changes should be considered. The Study provided a comprehensive framework for evaluating the Plan's current asset allocation relative to other potential asset allocations, including alternative asset classes, to determine if an alternative asset allocation would be more effective in meeting the Plan's liabilities and investment objectives.

b. Numerous alternative asset classes were reviewed and screened with several new asset classes being included as options in the Study. Several asset allocation portfolios were modeled by Segal Marco Advisors and reviewed by the Retirement Fund Trust Selection Committee.

c. The Retirement Fund Trust Selection Committee is recommending the addition of two new asset classes to the Statement of Investment Policy ("Investment Policy"). The new asset classes include Infrastructure Equity and Private Equity investments. Based on modeling results, recommended changes to the current investment portfolio are expected to provide higher average annual returns with a minimal impact on volatility than those forecasted for the current portfolio.

ACTION
Board approval for the Investment Policy being updated to reflect the proposed changes. Primary changes to the Policy include:

1. Two new asset classes have been added.
2. One current asset class has been removed.
3. Asset allocation targets and ranges have been revised.

RECOMMENDED:

DocuSigned by:
Brad Underwood
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Bradley R. Underwood
Vice President and Chief Financial Officer

APPROVED FOR BOARD CONSIDERATION:

Signed by:
L. Javier Fernandez
AC309FDCE56247E...

L. Javier Fernandez
President and Chief Executive Officer

BRU: jwt

Attachments:
Statement of Investment Policy for the Omaha Public Power District Retirement Plan – Clean
Statement of Investment Policy for the Omaha Public Power District Retirement Plan – Redline
Resolution

Omaha Public Power District

Asset/Liability Modeling Study

Summary & Recommended Investment Policy Changes

November 6, 2026

John Thurber, *Omaha Public Power District*
Keith Reynolds, *Segal Marco Advisors*

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Segal Marco Advisors

Introduction

- As a reminder, OPPD engages the Retirement Plan Investment Advisor, Segal Marco Advisors “Segal Marco”, to conduct an in-depth Asset/Liability Modeling Study (“ALM Study”) every 4-5 years.
- This ALM Study seeks to provide the following:
  - A distribution of outcomes for key asset-liability variables, so that expected and possible worst-case case outcomes can be highlighted and quantified.
  - A summary of how those distributions may change if the asset allocation is altered.
  - Alternative asset allocations were chosen that either (a) improve median results, (b) mitigate worst-case results, or both.
- The latest ALM Study was completed in the 3rd Quarter 2026 and the results shared with the Board of Directors in October.

2026 ALM Study Results

	Current	*Recommend*	*Alternative*
Inflation Linked Bonds	0.0%	0.0%	0.0%
Core Fixed Income	28.0%	25.0%	25.0%
High Yield	0.0%	0.0%	0.0%
Emerging Markets Debt (50% LC)	5.0%	5.0%	5.0%
US Equity	28.0%	28.0%	28.0%
Developed International Equity (U)	10.0%	12.5%	12.5%
International Small Cap	4.0%	0.0%	0.0%
Emerging Markets Equity	10.0%	7.5%	7.5%
Private Equity	0.0%	4.0%	0.0%
Private Credit	7.5%	7.5%	7.5%
Core Real Estate (UL)	7.5%	7.5%	7.5%
Infrastructure	0.0%	3.0%	7.0%
Long-term Arithmetic Return	**7.0%**	**7.2%**	**7.1%**
Long-term Compound Return	**6.5%**	**6.7%**	**6.6%**
Portfolio Volatility	**10.5%**	**10.5%**	**10.3%**
Sharpe Ratio	*0.368*	*0.383*	*0.379*
Compound Return 10 Yr	**6.5%**	**6.7%**	**6.5%**

- After much analysis, two asset allocations surfaced that provide an attractive risk/reward benefit as compared to **"Current"**.
- **"Recommend"** adds 7% to the private markets allocation and introduces two new asset classes (Private Equity & Infrastructure), while reducing Public Equity by 4% and Fixed Income by 3%.
  - The Recommended asset mix maintains the current risk level but improves the long-term expected return the most (due to the inclusion of Private Equity).
  - It is also is the most efficient mix in terms of providing the highest Share Ratio (return per unit of risk).
- **"Alternative"** adds 7% to the private markets' allocation (via the same sources) but only adds Infrastructure.

Infrastructure Overview

- Infrastructure is an investment strategy whose assets are essential for the distribution of people, goods and resources across the global economies and the functioning of society and commerce.
- We are seeking a Core Fund that holds a diversified mix of underlying stable/low volatility income driven private Infrastructure investments.

Key target sectors



Distinct characteristics:

01 Strong market positions/ High barriers to entry

02 Long asset/ concession life

03 Inflation protection

04 Benefit from regional/ global economic growth

05 Stable and predictable revenues

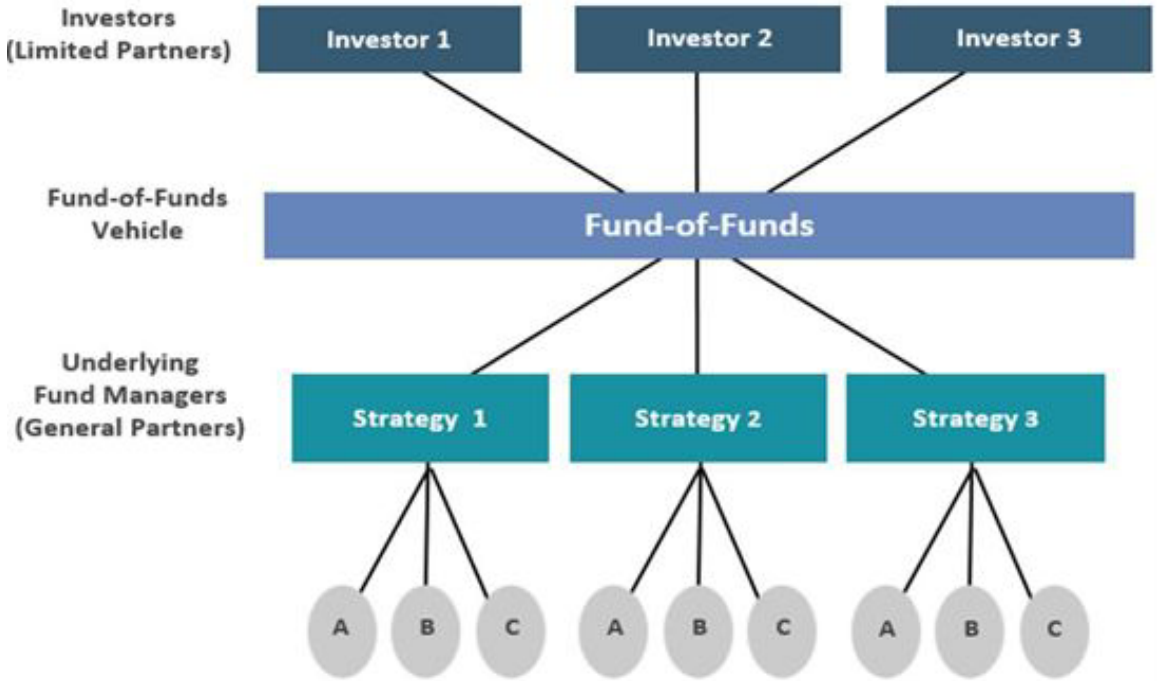
06 Stable regulatory environment

07 Targeting investment-grade financing

The expected Net IRR for a Core Infrastructure Fund is 8-12%

Private Equity Overview

- Private Equity is a multi-trillion dollar global industry that entails investing across of non-public companies through privately negotiated transactions and results in the private ownership of businesses. A few current examples of Private Equity backed companies include Walgreens, PetSmart, Skechers, and Staples.
- We believe the most prudent and risk-controlled approach for OPPD to gain initial exposure to Private Equity is through a Diversified Multi-Strategy Fund-of-Funds manager.



Benefits of Fund-of-Funds Approach:

- Access to top-tier managers
- Dedicated research team
- Disciplined investment process and portfolio monitoring
- Diversification, overall risk reduction
- Reporting efficiency and administrative ease
- Negotiated fees through scale of Segal Marco

The expected Net IRR for a Diversified Multi-Strategy Private Equity Fund is 15-20%

Investment Policy Statement – Suggested Changes

ARTICLE IV

STATEMENT OF INVESTMENT POLICY

Section 1. Asset Allocation Targets and Ranges

It shall be the policy of the Plan to invest in each asset class ranging between a minimum and a maximum of total Trust assets as shown below.

Asset Class as a Percent of Total Assets

Asset Class	Minimum	Target	Maximum
US Large Cap Equity	14.0%	18.0%	22.0%
US Mid Cap Equity	3.5%	5.0%	6.5%
US Small Cap Equity	3.5%	5.0%	6.5%
Non-US Equity (Developed ~~Large~~)	~~8.0%~~10.0%	~~10.0%~~12.5%	~~12.0%~~15.0%
~~Non-US Equity (Developed Small)~~	~~2.5%~~	~~4.0%~~	~~5.5%~~
Emerging Markets Equity	~~8.0%~~5.0%	~~10.0%~~7.5%	~~12.0%~~10.0%
Domestic Fixed Income	~~18.0%~~15.0%	~~23.0%~~20.0%	~~28.0%~~25.0%
High Yield Fixed Income	2.0%	3.0%	4.0%
Treasury Inflation Protected Securities	0.0%	2.0%	3.0%
Emerging Market Fixed Income	3.5%	5.0%	6.5%
Private Credit	0.0%	7.5%	~~12.5%~~10.0%
Private Real Estate	5.0%	7.5%	10.0%
Infrastructure	0.0%	3.0%	10.0%
Private Equity	0.0%	4.0%	5.0%

The Committee with the approval of the Board of Directors will determine which asset classes will be actively versus passively managed. The asset classes may include both actively and passively managed funds.

Implementation Recommendations:

1) Reduce Overseas Equity Risk
   - Reduce Emerging Markets Equity by 2.5%
   - Increase Non-US Equity (Developed) 2.5%
2) Remove underperforming International Small Cap manager with proceeds funding Private Equity
3) Reduce Domestic Fixed Income by 3% with proceeds funding Infrastructure
4) Infrastructure maximum range is set higher to 10% in the event that Private Equity is not funded and assets shifted to Infrastructure
5) The Committee will review and may make adjustments on the usage of active and passive management across the Plan.

Conclusions

Why are we making this recommendation?

- Enhancing diversification via modest allocations to private market investments provides the Plan with the opportunity to generate excess return across a variety of market environments.
- The Investment Committee found the “Recommended” mix most appealing, as the allocation maintains the current risk level of the Plan, but improves the long-term expected return the most (due to the inclusion of Private Equity).
  - It is also was the most efficient mix in terms of providing the highest Share Ratio (return per unit of risk).
- In addition, Segal Marco Research believes it is an attractive time to invest in Private Equity.
  - Valuations are lower (buyers' market), providing new Private Equity funds an opportunity to deliver outsized returns.

Conclusions

Next Steps

- Following Board approval of the Investment Policy Statement, Segal Marco will profile and review several Infrastructure and Private Equity funds with the Investment Committee.
- If the Investment Committee has any reservations making a Private Equity commitment in 2027, the Committee will revert to the "Alternative" mix and send the Private Equity allocation to Infrastructure.
  - The "Alternative" mix is also an improvement over Current allocation
  - **The updated Investment Policy Statement provides flexibility to include or not include Private Equity**
- In addition, the Investment Committee will begin the process of terminating the International Small Cap Manager and may make adjustments on the usage of active and passive management in the public equity portfolio.
- The Investment Committee will come back to the Board with new managers for review and approval in the first half of 2027.

STATEMENT OF INVESTMENT POLICY FOR THE OMAHA PUBLIC POWER DISTRICT RETIREMENT PLAN

As Approved by the OPPD Board of Directors
November 19, 2026

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ARTICLE I

INTRODUCTION

This document establishes the Investment Policy for the management of the assets of the Omaha Public Power District Retirement Plan (the "Plan").

This Statement of Investment Policy (the "Policy") represents the guiding document for overseeing the investment of all assets in the Plan. This Policy is to be communicated to the appointed Investment Managers (the "Managers") as their principal source for developing an appropriate investment strategy and serves as the basis for the Plan's performance evaluation.

Any changes to the guidelines defined by this Policy or exceptions to them, will be in writing and delivered to the Investment Managers.

This Policy was prepared with input and guidance from Segal Marco Advisors and approved by the Trust Selection Committee (the "Committee"). The Committee has arrived at this Policy through careful study of the returns and risks associated with alternative investment strategies. This Policy has been chosen as the most appropriate policy for achieving the financial objectives of the Plan, which are described in the Objectives section of this document.

The Committee has adopted a long-term investment horizon such that the chances and duration of investment losses are carefully weighed against the long-term potential for appreciation of assets.

The assets of the Plan will be invested in a manner that provides the safeguards and diversity that a prudent investor would adhere to. All transactions will be undertaken to fulfill the objectives of the Plan.

ARTICLE II

DUTIES AND RESPONSIBILITIES

The Committee is responsible for developing policy recommendations and for overseeing the investment activities of the Plan assets. The Committee must gain approval of the recommended changes to the Policy from the Board of Directors before they can be implemented.

The Committee's responsibilities include recommending revisions to this Policy as necessary such as, but not limited to, recommendations regarding (1) acceptable asset classes, (2) allowable ranges of holdings by asset class as a percent of assets, and (3) definitions of acceptable securities within each asset class.

The Committee (1) recommends the selection, retention and replacement of investment managers, investment advisers and custodians to the Board of Directors, (2) controls the asset allocation within policy limits and by individual investment managers, (3) establishes investment performance expectations for each portfolio, and (4) ensures all managers comply with this Policy.

The Committee or its designee will communicate the Policy and performance expectations to the investment managers. The Committee will also review investment performance regularly to assure the Policy is being followed and progress is being made toward achieving the objectives.

The Managers shall be responsible for determining investment strategy and implementing security selection and the timing of purchases and sales within the Policy guidelines set forth in this statement and as otherwise provided by the Committee.

Relative performance benchmarks for the Plan's investment managers are set forth in the Control Procedures section of this document.

ARTICLE III

STATEMENT OF OBJECTIVES

The assets of the Plan shall be invested in accordance with the objectives summarized below:

1. Improve the Plan's funded status over the long-term to maintain assets at or above 100% of the Fund's Termination Liability as calculated by the District's actuary.
2. Maximize returns within reasonable and prudent levels of risk.
3. Maintain sufficient liquidity to meet benefit payment obligations on a timely basis.
4. Maintain District contributions as a percentage of base payroll at or below employee contribution levels over the long-term (excluding amortized accrued liability contributions).

The Policy has been established in conjunction with a comprehensive review of both the current and projected financial requirements of the Plan and investment returns by asset class.

While there are no assurances that these objectives will be realized, it is believed that the likelihood of their realization is reasonably high based upon this Policy and historical performance of the asset classes discussed herein. The objectives have been based on a long-term investment horizon, so that interim fluctuations should be viewed with appropriate perspective.

ARTICLE IV

STATEMENT OF INVESTMENT POLICY

Section 1. Asset Allocation Targets and Ranges

It shall be the policy of the Plan to invest in each asset class ranging between a minimum and a maximum of total Trust assets as shown below.

Asset Class as a Percent of Total Assets

Asset Class	Minimum	Target	Maximum
US Large Cap Equity	14.0%	18.0%	22.0%
US Mid Cap Equity	3.5%	5.0%	6.5%
US Small Cap Equity	3.5%	5.0%	6.5%
Non-US Equity (Developed)	10.0%	12.5%	15.0%
Emerging Markets Equity	5.0%	7.5%	10.0%
Domestic Fixed Income	15.0%	20.0%	25.0%
High Yield Fixed Income	2.0%	3.0%	4.0%
Treasury Inflation Protected Securities	0.0%	2.0%	3.0%
Emerging Market Fixed Income	3.5%	5.0%	6.5%
Private Credit	0.0%	7.5%	10.0%
Private Real Estate	5.0%	7.5%	10.0%
Infrastructure	0.0%	3.0%	10.0%
Private Equity	0.0%	4.0%	5.0%

The Committee with the approval of the Board of Directors will determine which asset classes will be actively versus passively managed. The asset classes may include both actively and passively managed funds.

Section 2. Adherence to Policy Targets and Ranges

The Committee is guided by the philosophy that asset allocation is the most significant determinant of long-term investment return. The Plan asset allocation will be maintained as close to the target allocations as reasonably possible. Fund additions and withdrawals shall be allocated across portfolios to bring the asset mix as close to the target allocation as possible.

Rapid unanticipated market shifts may cause the asset mix to fall outside of the Policy range. These divergences should be of a short-term nature. The Committee through its designee will be responsible for ensuring that the Managers keep divergences from the Policy as brief as possible. This may require rebalancing the assets when necessary.

Section 3. Rebalancing Procedures

If the asset allocation cannot be maintained within the above Policy limits through contributions and withdrawals, the Committee or its designee shall direct the shifting of assets across investment management portfolios in accordance with the guidelines below. Such reallocations are anticipated to occur infrequently.

Where multiple investment portfolios per asset class are employed, target allocations for each portfolio will be set as a percent of the category assets. Rebalances among portfolios within asset classes will be made at the discretion of the Committee or its designee but must be made whenever portfolio market values diverge more than 10% above or below their target amounts expressed as a percent of the asset category.

Cash withdrawals from the portfolio will first be taken from asset classes and individual managers that are above their respective target commitments.

Any portfolio that is out of compliance will be rebalanced back within the allowable range.

When a rebalance is required, withdrawals of funds from portfolios above their target allocations will be invested in the portfolios that are the most underweighted with respect to their benchmarks. To rebalance portfolios that are underweighted with respect to their percent of assets limits, withdrawals will be made first from the portfolios that are the most overweighted.

The Committee's designee will monitor the actual asset allocation compared to the target allocations each quarter to determine if rebalancing is required.

Section 4. Diversification

Investments shall be diversified with the intent to minimize the risk of large losses. Consequently, the total portfolio will be constructed and maintained to provide prudent diversification with regard to the concentration of holdings in individual issues, corporations, or industries.

Not more than 5% of the total of all stock portfolios valued at market may be invested in the common stock of any one corporation. A position greater than 5% of the portfolio at market should be highlighted and explained by the investment manager. Not more than 5% of the outstanding shares of any one company may be held. Not more than 25% of stock valued at market may be held in any one industry category as defined by the Plan's Investment Advisor.

With the exception of securities issued by the U.S. Government and its agencies, no single fixed income issue will represent more than 5% of the total portfolio as measured by market value at time of purchase. Holdings of any individual issue must be 5% or less of the value of the total issue.

It is recognized that individual portfolios or funds may have greater concentrations of individual companies, but these portfolios should be offset by other portfolios or funds of complementary styles should offset these portfolios such that the total of all equity holdings complies with these diversification maximums.

The diversity guidelines above will be monitored on a quarterly basis by the Investment Advisor and adjustments will be made accordingly.

Section 5. Volatility

Consistent with the desire for adequate diversification, the Policy is based on the assumption that the volatility of the combined portfolios will be similar to that of the market opportunity available to institutional investors with similar return objectives.

The volatility of each Manager's portfolio will be compared to the volatility of appropriate market indices and peer groups.

Section 6. Liquidity

When the amount and timing of withdrawals are determined, the Committee or its designee will notify the Managers as far in advance as possible of any withdrawal orders to allow them sufficient time to build up necessary liquid reserves.

Section 7. Voting of Proxies

It is expected the Managers will review each proxy ballot and vote them in a manner that preserves and enhances shareholder value.

Each Manager shall keep accurate written records of all proxy votes, and provide a detailed report to the Committee documenting all votes upon request.

Section 8. Execution of Security Trades

The Committee expects the purchase and sale of securities to be made through responsible brokers in a manner designed to receive the best combination of realized prices and commission rates.

Section 9. Securities Lending

The portfolio may participate in securities lending only in those portfolios where the Committee has specifically approved its use. The securities lending program will be designed to generate incremental income from lending securities to qualified borrowers who provide collateral in exchange for the right to use the securities. The investing of this collateral is expected to follow the investment guidelines developed by the Plan portfolio with the principal objectives being liquidity and preservation of capital. There are no goals or expectations on a specific amount of income to be generated from the securities lending program. The reason for setting no goals or expectations is to minimize incentives to violate the guidelines established in an effort to generate higher income levels. Incremental income levels will be dictated by the market's demand for securities in the Plan portfolio.

Section 10. Deviations From This Policy

It is recognized that new or unique investment opportunities may become available from time to time which are not specifically addressed in this Policy Statement. As such, the Committee may approve minor deviations from this Policy, provided that the Committee believes any and all deviations will enhance long-term return expectations and not increase the Plan's exposure to investment losses.

All material policy deviations approved should be reported to the Omaha Public Power District Board of Directors at the next scheduled review of the Plan Policy and performance.

ARTICLE V

GUIDELINES FOR SECURITY HOLDINGS

Section 1. Commingled Securities Holdings

In addition to direct investment in individual securities, the Plan will utilize mutual funds and other commingled investments. It is understood that it may not be possible to adhere completely to the following guidelines. The Plan will notify its managers of these Policy guidelines and request the maximum feasible compliance.

Section 2. U.S. Equity Security Holdings

Equity holdings shall be restricted to readily marketable securities of corporations that are actively traded in significant volume on major exchanges including NASDAQ in the U.S. Equity holdings may include American Depositary Receipts traded on U.S. exchanges. Preferred and convertible preferred stocks may be held. Publicly traded Real Estate Investment Trust (REITs) shares may be held and are considered part of the allocation to stocks if they are held in a portfolio classified as U.S. Equity.

For the purposes of this Policy, small and mid cap stocks are defined as having market capitalizations of $10 Billion or less. Stocks with capitalizations above $10 Billion are included in the Large Cap U.S. Equity commitment.

There is no minimum market capitalization for holdings of individual issues. However, each holding shall be of a sufficiently low percentage of average daily trading volume to ensure sale on favorable terms at the appropriate time.

Futures and options can be used as a substitute for equity securities provided that they are 100% collateralized by highly liquid, low volatility fixed income securities and therefore do not represent leveraging of the assets.

Section 3. Non-U.S. Equity Security Holdings

All Non-U.S. equity holdings shall be highly liquid securities issued by corporations headquartered in countries included in the Morgan Stanley Capital All Country World ex US Index. Issues may also be purchased and sold on exchanges in other countries that offer a ready and continuous market for individual issues and have no restrictions on the transfer of funds to and from the U.S. Managers holding Non-U.S. dollar denominated securities are permitted to employ currency-hedging strategies.

Section 4. Fixed Income Security Holdings

Fixed income investments shall be marketable securities, which may include, but not necessarily be limited to U. S. Treasury, Federal Agencies and U.S. Government guaranteed obligations, and corporate issues including convertibles. Mortgage pass-throughs, collateralized debt obligations and non-dollar denominated bonds may be held.

The total fixed income portfolio must have a weighted average rating of A or better in the aggregate as determined by at least one credit rating service. In cases where the yield spread adequately

compensates for additional risk, up to 10% of the value of each fixed income portfolio, with the exception of the High Yield Fixed Income Portfolio, may be invested in below investment grade securities provided that they are easily tradable and overall fixed income quality is maintained.

Investment grade quality is defined as BBB rated or higher at time of purchase. In cases where credit rating agencies assign different quality ratings to a security, the lower rating will be used. Should the rating of a fixed income security fall below minimum investment grade, the manager may continue to hold the security if they believe the security will be upgraded in the future, there is low risk of default, and buyers will continue to be available throughout the anticipated holding period. The Manager has the responsibility of notifying the Committee whenever an issue falls below investment grade. The notification should include the Manager's assessment of the issue's credit rating and its ongoing role in the portfolio.

Non U.S. dollar fixed income holdings are allowed to be held in the Plan. Non U.S. dollar securities must be highly liquid, actively traded, and rated single A or higher at time of purchase. The only exception is for Emerging Market Debt Securities, which may be held in a portfolio designated for such securities.

Mortgage securities held should exhibit price, volatility, and liquidity similar to components of the Barclays Mortgage Backed Securities Index. The intent is to invest only in the most conservative mortgage instruments. These may include collateralized mortgage obligations such as pass-throughs, sequential CMO traunches, or planned amortization classes. Asset backed securities including categories other than mortgages may be held provided they are un-leveraged, low risk and their values do not change due to the performance of any other security, index or commodity (i.e., structured notes). In determining the acceptability of a derivative, duration must be easily calculated and where duration cannot be calculated, the investment is not permissible.

Privately placed fixed income issues may be held provided that the credit risk is carefully evaluated and judged to conform to this Policy, and that there is a secondary market for potential sale before maturity or call date.

Futures and options can be used as a substitute for fixed income provided that they are 100% collateralized by highly liquid, low volatility fixed income securities and therefore do not represent leveraging of the assets.

If an investment manager investing in a separate account for the Plan has any questions about the authorization granted to purchase and/or hold a security because of its issuer, type, effective duration, or effective credit quality, the manager must consult with the Committee prior to purchase of the security. In addition, no separate account investment will be made in any newly developed instrument without the explicit consent of the Committee.

Section 5. Private Credit Holdings:

The private credit portion of the Plan's assets will be invested through an investment manager. Private credit managers are expected to be focused on providing cash-flow based financing to medium size private companies located primarily in the U.S. and be invested near the top of the capital structure.

Section 6. Private Real Estate Holdings:

The private real estate portion of the Plan's assets will be invested through an investment manager. Private real estate managers are expected to hold a diversified pool of real estate investments.

Section 7. Infrastructure Holdings:

The infrastructure portion of the Plan's assets will be invested through an investment manager. Private infrastructure managers are expected to hold a broad pool of infrastructure investments that are well diversified by sector and geography.

Section 8. Private Equity Holdings:

The private equity portion of the Plan's assets will be invested through an investment manager. Private Equity managers are expected to hold a diversified pool of underlying Private Equity funds and companies. A multi-strategy approach is expected to reduce risk associated with any single underlying investment.

Section 9. Cash Holdings

It shall be the policy of the Plan to be fully invested to the maximum extent possible. Any excess cash holdings in separate short-term fixed income accounts should be based upon the anticipated spending needs of the Fund plus a limited margin of safety.

It is understood that the Plan Managers at any point in time may not be fully invested. While the Plan's assets may be partially invested in cash equivalents, for asset allocation purposes, these funds shall be considered invested in the asset classes of the respective managers. In turn, each Manager's performance will be evaluated on the total amount of assets under its direct management.

Uninvested cash balances should be kept to a minimum through the prompt investment of available funds. For actively managed equity portfolios, cash and short-term instruments maturing in less than 360 days shall be restricted to 5% of the market value of each portfolio except for brief periods. Exceptions are allowed when building liquidity in anticipation of a large withdrawal or by special permission from the Committee.
Cash equivalent holdings are allowed in the fixed income portfolio to maintain the portfolio duration within Policy limits. Cash equivalent reserves shall consist of cash instruments having quality ratings by at least one rating agency of A-2, P-2 or higher, maturing in 360 days or less.
Should any investment manager wish to exceed the guideline limits, special prior approval by the Committee will be needed. For special situations, the Committee can grant special exemptions in writing from the guidelines. In no case can a manager intentionally exceed guideline limits without formal prior approval by the Committee.

Section 10. Prohibited Transactions

The following securities and transactions are not authorized:

a) Unregistered equity securities;

b) Commodities or commodity contracts (except for unleveraged stock or bond index futures and currency futures and options).

Any financial options and futures employed must be solely for defensive and hedge strategies undertaken to protect principal.

No investments shall be made for the purpose of engaging in speculative trading.

ARTICLE VI

CONTROL PROCEDURES

Section 1. Review of Liabilities

All major liability assumptions regarding number of participants, benefit levels and actuarial assumptions will be subject to an annual review by the Committee consistent with applicable State and Federal Statutes. This review will focus on the Plan's growth assumptions and actual experience.

Section 2. Review of Investment Objectives

Investment objectives will be reviewed annually to determine the continued feasibility of achieving the investment objectives and the appropriateness of the Policy for achieving these objectives in light of the review of cash flow and Fund growth.

It is not expected that the Policy will change frequently. In particular, short-term changes in the financial markets should not require an adjustment in the Policy.

Section 3. Review of Investment Managers

The Committee will review the performance of the total of all investments and individual Manager performance quarterly. The Investment Adviser or other designee will monitor each Manager to identify any material changes that may affect their ability to perform their duties. The Committee will meet with each Manager to review the goals, objectives, guidelines and performance, including total rate of return of their portfolio(s) as needed. Any recommendations by the Manager as to changes in the investment guidelines should be submitted to the Committee in writing.

For small dollar placements in mutual funds, annual reviews may be conducted by telephone.

Performance reviews will focus on:

- Comparison of Managers' results to funds using similar policies (in terms of diversification, volatility, style, etc.)
- Comparison to indices appropriate for monitoring individual portfolio investment strategies.
- Total Fund and Manager adherence to the Policy guidelines.
- Material changes in the Manager organizations, such as in investment philosophy, personnel, acquisitions or losses of major accounts, etc.

The Committee encourages the Managers to have open communication with them on all significant matters pertaining to investment policies and the management of the Plan's assets entrusted to them.

The Managers are responsible for keeping the Committee, or its designee, advised of any material changes in personnel, investment strategy, or other pertinent information potentially affecting performance of their portfolios.

Section 4. Performance Expectations

The most important performance expectation is the achievement of long-term investment results that are consistent with the Plan's Policy. Implementation of the Policy will be directed toward achieving this return and not toward maximizing return without regard to risk.

In order to ensure that investment opportunities available over specific time periods are fairly evaluated, the Committee will use comparative performance statistics to evaluate investment results.

The total Plan will be expected to achieve and maintain minimum performance as follows:

1) Exceed an appropriate benchmark index, net of management fees.

2) Earn a rate-of-return on the Retirement Fund assets that is at least 4% greater than the rate of inflation over a ten-year planning horizon.

Each investment manager will be expected to achieve and maintain minimum performance as follows:

1) Rank in the top 40% of an appropriate peer group of portfolios.

2) Exceed an appropriate benchmark index, net of management fees.

While these performance standards should be achieved over a complete market cycle, the Committee will also monitor performance over rolling three and five year time periods.

Section 5. New Manager Criteria

The following parameters are established for those organizations seeking to manage a portion of the District's Retirement Plan assets. Plan fiduciaries should ensure that decisions regarding the hiring of an investment management firm are being made for the exclusive benefit of the plan participants.

- A MINIMUM OF FIVE YEARS IN BUSINESS PRACTICING THE PROPOSED DISCIPLINE

- A MINIMUM OF $500 MILLION UNDER MANAGEMENT IN THE PROPOSED DISCIPLINE

- A PERFORMANCE HISTORY THAT ***RANKS COMPETITIVELY*** IN AN APPROPRIATE DATA BASE OF A NATIONALLY-RECOGNIZED PERFORMANCE MEASUREMENT SERVICE OVER THE LAST FIVE YEARS

- OTHER MORE SPECIFIC CRITERIA BASED ON STYLE AND/OR ASSET CLASS CONSIDERATIONS

The only exception to the preceding criteria would be for consideration of an emerging or protected class firm. In those cases, the qualification requirements will focus on more subjective elements including the credentials of key decision makers:

- APPROPRIATE ACADEMIC BACKGROUND - MBA AND/OR CFA DESIGNATION

- A MINIMUM OF FIVE YEARS' EXPERIENCE IN THE PROPOSED DISCIPLINE

Other criteria to be evaluated by the District will include the depth of the firm's support staff, its research capabilities, and its business affiliations. Managers hired under these conditions will have a maximum initial funding of $10 million.

Section 6. Performance Measurement Standards

Asset Class/Manager	Peer Universe	Benchmark Index
OBJECTIVE:	Exceed 40th Percentile	Active: Outperform Net of Investment Fees Passive: Perform In-line[1]
U.S. Equities:		
Large Cap	Large Cap Core	Russell 1000
Mid-Cap	Mid Cap Core	S&P MidCap 400
Small Cap Value	Small Cap Value	Russell 2000 Value
Small Cap Growth	Small Cap Growth	Russell 2000 Growth
Non U.S. Equities:		
Developed Markets	International Equities	MSCI EAFE (Net)
Emerging Markets	Emerging Markets Equity	MSCI EM (Net)
U.S. Fixed Income:		
Core	Core Fixed Income	Bloomberg U.S. Aggregate
High Yield	High Yield Fixed Income	FTSE High Yield Mkt
TIPS	TIPS Funds	Bloomberg U.S. TIPS
Non U.S. Fixed Income:		
Emerging Markets	Emerging Markets Fixed	JPM EMBI Global
Alternatives:		
Private Credit	Not Applicable	To Be Determined[2]
Private Real Estate	Real Estate Funds	NCREIF ODCE
Infrastructure	Not Applicable	To Be Determined[2]
Private Equity	Not Applicable	To Be Determined[2]
Total Plan:		Custom

POLICY APPROVAL DATE: November 19, 2026

(1) Passive management may be utilized but the manager may only be invested in securities that are consistent with the assigned index.

(2) Benchmarks for private credit, infrastructure and private equity, investments are product specific and can include opportunity costs as measures.

STATEMENT OF INVESTMENT POLICY FOR THE OMAHA PUBLIC POWER DISTRICT RETIREMENT PLAN

As Approved by the OPPD Board of Directors
~~January 20, 2022~~November 19, 2026

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ARTICLE I

INTRODUCTION

This document establishes the Investment Policy for the management of the assets of the Omaha Public Power District Retirement Plan (the "Plan").

This Statement of Investment Policy (the "Policy") represents the guiding document for overseeing the investment of all assets in the Plan. This Policy is to be communicated to the appointed Investment Managers (the "Managers") as their principal source for developing an appropriate investment strategy and serves as the basis for the Plan's performance evaluation.

Any changes to the guidelines defined by this Policy or exceptions to them, will be in writing and delivered to the Investment Managers.

This Policy was prepared with input and guidance from Segal Marco Advisors and approved by the Trust Selection Committee (the "Committee"). The Committee has arrived at this Policy through careful study of the returns and risks associated with alternative investment strategies. This Policy has been chosen as the most appropriate policy for achieving the financial objectives of the Plan, which are described in the Objectives section of this document.

The Committee has adopted a long-term investment horizon such that the chances and duration of investment losses are carefully weighed against the long-term potential for appreciation of assets.

The assets of the Plan will be invested in a manner that provides the safeguards and diversity that a prudent investor would adhere to. All transactions will be undertaken to fulfill the objectives of the Plan.

ARTICLE II

DUTIES AND RESPONSIBILITIES

The Committee is responsible for developing policy recommendations and for overseeing the investment activities of the Plan assets. The Committee must gain approval of the recommended changes to the Policy from the Board of Directors before they can be implemented.

The Committee's responsibilities include recommending revisions to this Policy as necessary such as, but not limited to, recommendations regarding (1) acceptable asset classes, (2) allowable ranges of holdings by asset class as a percent of assets, and (3) definitions of acceptable securities within each asset class.

The Committee (1) recommends the selection, retention and replacement of investment managers, investment advisers and custodians to the Board of Directors, (2) controls the asset allocation within policy limits and by individual investment managers, (3) establishes investment performance expectations for each portfolio, and (4) ensures all managers comply with this Policy.

The Committee or its designee will communicate the Policy and performance expectations to the investment managers. The Committee will also review investment performance regularly to assure the Policy is being followed and progress is being made toward achieving the objectives.

The Managers shall be responsible for determining investment strategy and implementing security selection and the timing of purchases and sales within the Policy guidelines set forth in this statement and as otherwise provided by the Committee.

Relative performance benchmarks for the Plan's investment managers are set forth in the Control Procedures section of this document.

ARTICLE III

STATEMENT OF OBJECTIVES

The assets of the Plan shall be invested in accordance with the objectives summarized below:

1. Improve the Plan's funded status over the long-term to maintain assets at or above 100% of the Fund's Termination Liability as calculated by the District's actuary.
2. Maximize returns within reasonable and prudent levels of risk.
3. Maintain sufficient liquidity to meet benefit payment obligations on a timely basis.
4. Maintain District contributions as a percentage of base payroll at or below employee contribution levels over the long-term (excluding amortized accrued liability contributions).

The Policy has been established in conjunction with a comprehensive review of both the current and projected financial requirements of the Plan and investment returns by asset class.

While there are no assurances that these objectives will be realized, it is believed that the likelihood of their realization is reasonably high based upon this Policy and historical performance of the asset classes discussed herein. The objectives have been based on a long-term investment horizon, so that interim fluctuations should be viewed with appropriate perspective.

ARTICLE IV

STATEMENT OF INVESTMENT POLICY

Section 1. Asset Allocation Targets and Ranges

It shall be the policy of the Plan to invest in each asset class ranging between a minimum and a maximum of total Trust assets as shown below.

Asset Class as a Percent of Total Assets

Asset Class	Minimum	Target	Maximum
US Large Cap Equity	14.0%	18.0%	22.0%
US Mid Cap Equity	3.5%	5.0%	6.5%
US Small Cap Equity	3.5%	5.0%	6.5%
Non-US Equity (Developed ~~Large~~)	~~8.0%~~10.0%	~~10.0%~~12.5%	~~12.0%~~15.0%
~~Non-US Equity (Developed Small)~~	~~2.5%~~	~~4.0%~~	~~5.5%~~
Emerging Markets Equity	~~8.0%~~5.0%	~~10.0%~~7.5%	~~12.0%~~10.0%
Domestic Fixed Income	~~18.0%~~15.0%	~~23.0%~~20.0%	~~28.0%~~25.0%
High Yield Fixed Income	2.0%	3.0%	4.0%
Treasury Inflation Protected Securities	0.0%	2.0%	3.0%
Emerging Market Fixed Income	3.5%	5.0%	6.5%
Private Credit	0.0%	7.5%	~~12.5%~~10.0%
Private Real Estate	5.0%	7.5%	10.0%
Infrastructure	0.0%	3.0%	10.0%
Private Equity	0.0%	4.0%	5.0%

The Committee with the approval of the Board of Directors will determine which asset classes will be actively versus passively managed. The asset classes may include both actively and passively managed funds.

Section 2. Adherence to Policy Targets and Ranges

The Committee is guided by the philosophy that asset allocation is the most significant determinant of long-term investment return. The Plan asset allocation will be maintained as close to the target allocations as reasonably possible. Fund additions and withdrawals shall be allocated across portfolios to bring the asset mix as close to the target allocation as possible.

Rapid unanticipated market shifts may cause the asset mix to fall outside of the Policy range. These divergences should be of a short-term nature. The Committee through its designee will be responsible for ensuring that the Managers keep divergences from the Policy as brief as possible. This may require rebalancing the assets when necessary.

Section 3. Rebalancing Procedures

If the asset allocation cannot be maintained within the above Policy limits through contributions and withdrawals, the Committee or its designee shall direct the shifting of assets across investment management portfolios in accordance with the guidelines below. Such reallocations are anticipated to occur infrequently.

Where multiple investment portfolios per asset class are employed, target allocations for each portfolio will be set as a percent of the category assets. Rebalances among portfolios within asset classes will be made at the discretion of the Committee or its designee but must be made whenever portfolio market values diverge more than 10% above or below their target amounts expressed as a percent of the asset category.

Cash withdrawals from the portfolio will first be taken from asset classes and individual managers that are above their respective target commitments.

Any portfolio that is out of compliance will be rebalanced back within the allowable range.

When a rebalance is required, withdrawals of funds from portfolios above their target allocations will be invested in the portfolios that are the most underweighted with respect to their benchmarks. To rebalance portfolios that are underweighted with respect to their percent of assets limits, withdrawals will be made first from the portfolios that are the most overweighted.

The Committee's designee will monitor the actual asset allocation compared to the target allocations each quarter to determine if rebalancing is required.

Section 4. Diversification

Investments shall be diversified with the intent to minimize the risk of large losses. Consequently, the total portfolio will be constructed and maintained to provide prudent diversification with regard to the concentration of holdings in individual issues, corporations, or industries.

Not more than 5% of the total of all stock portfolios valued at market may be invested in the common stock of any one corporation. A position greater than 5% of the portfolio at market should be highlighted and explained by the investment manager. Not more than 5% of the outstanding shares of any one company may be held. Not more than 25% of stock valued at market may be held in any one industry category as defined by the Plan's Investment Advisor.

With the exception of securities issued by the U.S. Government and its agencies, no single fixed income issue will represent more than 5% of the total portfolio as measured by market value at time of purchase. Holdings of any individual issue must be 5% or less of the value of the total issue.

It is recognized that individual portfolios or funds may have greater concentrations of individual companies, but these portfolios should be offset by other portfolios or funds of complementary styles should offset these portfolios such that the total of all equity holdings complies with these diversification maximums.

The diversity guidelines above will be monitored on a quarterly basis by the Investment Advisor and adjustments will be made accordingly.

Section 5. Volatility

Consistent with the desire for adequate diversification, the Policy is based on the assumption that the volatility of the combined portfolios will be similar to that of the market opportunity available to institutional investors with similar return objectives.

The volatility of each Manager's portfolio will be compared to the volatility of appropriate market indices and peer groups.

Section 6. Liquidity

When the amount and timing of withdrawals are determined, the Committee or its designee will notify the Managers as far in advance as possible of any withdrawal orders to allow them sufficient time to build up necessary liquid reserves.

Section 7. Voting of Proxies

It is expected the Managers will review each proxy ballot and vote them in a manner that preserves and enhances shareholder value.

Each Manager shall keep accurate written records of all proxy votes, and provide a detailed report to the Committee documenting all votes upon request.

Section 8. Execution of Security Trades

The Committee expects the purchase and sale of securities to be made through responsible brokers in a manner designed to receive the best combination of realized prices and commission rates.

Section 9. Securities Lending

The portfolio may participate in securities lending only in those portfolios where the Committee has specifically approved its use. The securities lending program will be designed to generate incremental income from lending securities to qualified borrowers who provide collateral in exchange for the right to use the securities. The investing of this collateral is expected to follow the investment guidelines developed by the Plan portfolio with the principal objectives being liquidity and preservation of capital. There are no goals or expectations on a specific amount of income to be generated from the securities lending program. The reason for setting no goals or expectations is to minimize incentives to violate the guidelines established in an effort to generate higher income levels. Incremental income levels will be dictated by the market's demand for securities in the Plan portfolio.

Section 10. Deviations From This Policy

It is recognized that new or unique investment opportunities may become available from time to time which are not specifically addressed in this Policy Statement. As such, the Committee may approve minor deviations from this Policy, provided that the Committee believes any and all deviations will enhance long-term return expectations and not increase the Plan's exposure to investment losses.

All material policy deviations approved should be reported to the Omaha Public Power District Board of Directors at the next scheduled review of the Plan Policy and performance.

ARTICLE V

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Section 1. Commingled Securities Holdings

In addition to direct investment in individual securities, the Plan will utilize mutual funds and other commingled investments. It is understood that it may not be possible to adhere completely to the following guidelines. The Plan will notify its managers of these Policy guidelines and request the maximum feasible compliance.

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Equity holdings shall be restricted to readily marketable securities of corporations that are actively traded in significant volume on major exchanges including NASDAQ in the U.S. Equity holdings may include American Depositary Receipts traded on U.S. exchanges. Preferred and convertible preferred stocks may be held. Publicly traded Real Estate Investment Trust (REITs) shares may be held and are considered part of the allocation to stocks if they are held in a portfolio classified as U.S. Equity.

For the purposes of this Policy, small and mid cap stocks are defined as having market capitalizations of $10 Billion or less. Stocks with capitalizations above $10 Billion are included in the Large Cap U.S. Equity commitment.

There is no minimum market capitalization for holdings of individual issues. However, each holding shall be of a sufficiently low percentage of average daily trading volume to ensure sale on favorable terms at the appropriate time.

Futures and options can be used as a substitute for equity securities provided that they are 100% collateralized by highly liquid, low volatility fixed income securities and therefore do not represent leveraging of the assets.

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All Non-U.S. equity holdings shall be highly liquid securities issued by corporations headquartered in countries included in the Morgan Stanley Capital All Country World ex US Index. Issues may also be purchased and sold on exchanges in other countries that offer a ready and continuous market for individual issues and have no restrictions on the transfer of funds to and from the U.S. Managers holding Non-U.S. dollar denominated securities are permitted to employ currency-hedging strategies.

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The total fixed income portfolio must have a weighted average rating of A or better in the aggregate as determined by at least one credit rating service. In cases where the yield spread adequately

compensates for additional risk, up to 10% of the value of each fixed income portfolio, with the exception of the High Yield Fixed Income Portfolio, may be invested in below investment grade securities provided that they are easily tradable and overall fixed income quality is maintained.

Investment grade quality is defined as BBB rated or higher at time of purchase. In cases where credit rating agencies assign different quality ratings to a security, the lower rating will be used. Should the rating of a fixed income security fall below minimum investment grade, the manager may continue to hold the security if they believe the security will be upgraded in the future, there is low risk of default, and buyers will continue to be available throughout the anticipated holding period. The Manager has the responsibility of notifying the Committee whenever an issue falls below investment grade. The notification should include the Manager's assessment of the issue's credit rating and its ongoing role in the portfolio.

Non U.S. dollar fixed income holdings are allowed to be held in the Plan. Non U.S. dollar securities must be highly liquid, actively traded, and rated single A or higher at time of purchase. The only exception is for Emerging Market Debt Securities, which may be held in a portfolio designated for such securities.

Mortgage securities held should exhibit price, volatility, and liquidity similar to components of the Barclays Mortgage Backed Securities Index. The intent is to invest only in the most conservative mortgage instruments. These may include collateralized mortgage obligations such as pass-throughs, sequential CMO traunches, or planned amortization classes. Asset backed securities including categories other than mortgages may be held provided they are un-leveraged, low risk and their values do not change due to the performance of any other security, index or commodity (i.e., structured notes). In determining the acceptability of a derivative, duration must be easily calculated and where duration cannot be calculated, the investment is not permissible.

Privately placed fixed income issues may be held provided that the credit risk is carefully evaluated and judged to conform to this Policy, and that there is a secondary market for potential sale before maturity or call date.

Futures and options can be used as a substitute for fixed income provided that they are 100% collateralized by highly liquid, low volatility fixed income securities and therefore do not represent leveraging of the assets.

If an investment manager investing in a separate account for the Plan has any questions about the authorization granted to purchase and/or hold a security because of its issuer, type, effective duration, or effective credit quality, the manager must consult with the Committee prior to purchase of the security. In addition, no separate account investment will be made in any newly developed instrument without the explicit consent of the Committee.

Section 5. Private Credit Holdings:

The private credit portion of the Plan's assets will be invested through an investment manager. Private credit managers are expected to be focused on providing cash-flow based financing to medium size private companies located primarily in the U.S. and be invested near the top of the capital structure.

Section 6. Private Real Estate Holdings:

The private real estate portion of the Plan's assets will be invested through an investment manager. Private real estate managers are expected to hold a diversified pools of real estate investments.

Section 7. Infrastructure Holdings:

The infrastructure portion of the Plan's assets will be invested through an investment manager. Private infrastructure managers are expected to hold a broad pool of infrastructure investments that are well diversified by sector and geography.

Section 8. Private Equity Holdings:

The private equity portion of the Plan's assets will be invested through an investment manager. Private Equity managers are expected to hold a diversified pool of underlying Private Equity funds and companies. A multi-strategy approach is expected to reduce risk associated with any single underlying investment.

Section 79. Cash Holdings

It shall be the policy of the Plan to be fully invested to the maximum extent possible. Any excess cash holdings in separate short-term fixed income accounts should be based upon the anticipated spending needs of the Fund plus a limited margin of safety.

It is understood that the Plan Managers at any point in time may not be fully invested. While the Plan's assets may be partially invested in cash equivalents, for asset allocation purposes, these funds shall be considered invested in the asset classes of the respective managers. In turn, each Manager's performance will be evaluated on the total amount of assets under its direct management.

Uninvested cash balances should be kept to a minimum through the prompt investment of available funds. For actively managed equity portfolios, cash and short-term instruments maturing in less than 360 days shall be restricted to 5% of the market value of each portfolio except for brief periods. Exceptions are allowed when building liquidity in anticipation of a large withdrawal or by special permission from the Committee.
Cash equivalent holdings are allowed in the fixed income portfolio to maintain the portfolio duration within Policy limits. Cash equivalent reserves shall consist of cash instruments having quality ratings by at least one rating agency of A-2, P-2 or higher, maturing in 360 days or less.
Should any investment manager wish to exceed the guideline limits, special prior approval by the Committee will be needed. For special situations, the Committee can grant special exemptions in writing from the guidelines. In no case can a manager intentionally exceed guideline limits without formal prior approval by the Committee.

Section ~~8~~10. Prohibited Transactions

The following securities and transactions are not authorized:

a) Unregistered equity securities;

b) Commodities or commodity contracts (except for unleveraged stock or bond index futures and currency futures and options)~~;~~.

~~c) All forms of Private Equity including, but not restricted to, venture capital or buyout funds.~~

Any financial options and futures employed must be solely for defensive and hedge strategies undertaken to protect principal.

No investments shall be made for the purpose of engaging in speculative trading.

ARTICLE VI

CONTROL PROCEDURES

Section 1. Review of Liabilities

All major liability assumptions regarding number of participants, benefit levels and actuarial assumptions will be subject to an annual review by the Committee consistent with applicable State and Federal Statutes. This review will focus on the Plan's growth assumptions and actual experience.

Section 2. Review of Investment Objectives

Investment objectives will be reviewed annually to determine the continued feasibility of achieving the investment objectives and the appropriateness of the Policy for achieving these objectives in light of the review of cash flow and Fund growth.

It is not expected that the Policy will change frequently. In particular, short-term changes in the financial markets should not require an adjustment in the Policy.

Section 3. Review of Investment Managers

The Committee will review the performance of the total of all investments and individual Manager performance quarterly. The Investment Adviser or other designee will monitor each Manager to identify any material changes that may affect their ability to perform their duties. The Committee will meet with each Manager to review the goals, objectives, guidelines and performance, including total rate of return of their portfolio(s) as needed. Any recommendations by the Manager as to changes in the investment guidelines should be submitted to the Committee in writing.

For small dollar placements in mutual funds, annual reviews may be conducted by telephone.

Performance reviews will focus on:

- Comparison of Managers' results to funds using similar policies (in terms of diversification, volatility, style, etc.)
- Comparison to indices appropriate for monitoring individual portfolio investment strategies.
- Total Fund and Manager adherence to the Policy guidelines.
- Material changes in the Manager organizations, such as in investment philosophy, personnel, acquisitions or losses of major accounts, etc.

The Committee encourages the Managers to have open communication with them on all significant matters pertaining to investment policies and the management of the Plan's assets entrusted to them.

The Managers are responsible for keeping the Committee, or its designee, advised of any material changes in personnel, investment strategy, or other pertinent information potentially affecting performance of their portfolios.

Section 4. Performance Expectations

The most important performance expectation is the achievement of long-term investment results that are consistent with the Plan's Policy. Implementation of the Policy will be directed toward achieving this return and not toward maximizing return without regard to risk.

In order to ensure that investment opportunities available over specific time periods are fairly evaluated, the Committee will use comparative performance statistics to evaluate investment results.

The total Plan will be expected to achieve and maintain minimum performance as follows:

1) Exceed an appropriate benchmark index, net of management fees.

2) Earn a rate-of-return on the Retirement Fund assets that is at least 4% greater than the rate of inflation over a ten-year planning horizon.

Each investment manager will be expected to achieve and maintain minimum performance as follows:

1) Rank in the top 40% of an appropriate peer group of portfolios.

2) Exceed an appropriate benchmark index, net of management fees.

While these performance standards should be achieved over a complete market cycle, the Committee will also monitor performance over rolling three and five year time periods.

Section 5. New Manager Criteria

The following parameters are established for those organizations seeking to manage a portion of the District's Retirement Plan assets. Plan fiduciaries should ensure that decisions regarding the hiring of an investment management firm are being made for the exclusive benefit of the plan participants.

- A MINIMUM OF FIVE YEARS IN BUSINESS PRACTICING THE PROPOSED DISCIPLINE

- A MINIMUM OF $500 MILLION UNDER MANAGEMENT IN THE PROPOSED DISCIPLINE

- A PERFORMANCE HISTORY THAT ***RANKS COMPETITIVELY*** IN AN APPROPRIATE DATA BASE OF A NATIONALLY-RECOGNIZED PERFORMANCE MEASUREMENT SERVICE OVER THE LAST FIVE YEARS

- OTHER MORE SPECIFIC CRITERIA BASED ON STYLE AND/OR ASSET CLASS CONSIDERATIONS

The only exception to the preceding criteria would be for consideration of an emerging or protected class firm. In those cases, the qualification requirements will focus on more subjective elements including the credentials of key decision makers:

- APPROPRIATE ACADEMIC BACKGROUND - MBA AND/OR CFA DESIGNATION

- A MINIMUM OF FIVE YEARS' EXPERIENCE IN THE PROPOSED DISCIPLINE

Other criteria to be evaluated by the District will include the depth of the firm's support staff, its research capabilities, and its business affiliations. Managers hired under these conditions will have a maximum initial funding of $10 million.

Section 6. Performance Measurement Standards

Asset Class/Manager	Peer Universe	Benchmark Index
OBJECTIVE:	Exceed 40th Percentile	Active: Outperform Net of Investment Fees Passive: Perform In-line[(1)]
U.S. Equities:		
~~Passive~~ Large Cap	Large Cap Core	Russell 1000
Mid-Cap	Mid Cap Core	S&P MidCap 400
Small Cap Value	Small Cap Value	Russell 2000 Value
Small Cap Growth	Small Cap Growth	Russell 2000 Growth
Non U.S. Equities:		
Developed Markets	International Equities	MSCI EAFE (Net)
~~International Small Cap~~	~~International Small Cap~~	~~MSCI EAFE Small Cap (Net)~~
Emerging Markets	Emerging Markets Equity	MSCI EM ~~Mkts~~ (Net)
U.S. Fixed Income:		
~~Passive~~ Core	Core Fixed Income	Bloomberg U.S. Aggregate
~~Active Core~~	~~Core Fixed Income~~	~~Citigroup BIG Index~~
High Yield	High Yield Fixed Income	~~Citigroup~~FTSE High Yield Mkt
TIPS	TIPS Funds	~~Barclays~~ Bloomberg U.S. TIPS
Non U.S. Fixed Income:		
Emerging Markets	Emerging Markets Fixed	JPM EMBI Global
Alternatives:		
Private Credit	Not Applicable	To Be Determined~~*~~[(2)]
Private Real Estate	Real Estate Funds	NCREIF ODCE
Infrastructure	Not Applicable	To Be Determined[(2)]
Private Equity	Not Applicable	To Be Determined[(2)]
Total Plan:		Custom

POLICY APPROVAL DATE: ~~January 20, 2022~~November 19, 2026

(1) Passive management may be utilized but the manager may only be invested in securities that are consistent with the assigned index.

~~(1)~~(2) Benchmarks for private credit, infrastructure and private equity, investments are product specific and can include opportunity costs as measures.

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Moody/Underwood

DRAFT
RESOLUTION NO. xxxx

WHEREAS, the District retained Segal Marco Advisors, the District's Retirement Plan Consultant, to perform an Asset/Liability Study ("Study") for the Retirement Plan ("Plan"), and

WHEREAS, the Study provided a comprehensive framework for evaluating the Plan's current asset allocation relative to other potential asset allocations, including alternative asset classes, to determine if an alternative asset allocation would be more effective in meeting the Plan's liabilities and investment objectives, and

WHEREAS, several sample asset allocation portfolios were modeled by Segal Marco Advisors and reviewed by the District's Trust Selection Committee, and

WHEREAS, the Trust Selection Committee is recommending a new portfolio adding two new asset classes and removing one current asset class, and

WHEREAS, the Board of Directors of the Omaha Public Power District concurs with the recommendation of the Trust Selection Committee and finds that the updated Statement of Investment Policy to incorporate this recommendation is in the best interest of the District and the District's Retirement Plan Participants.

NOW, THEREFORE, BE IT RESOLVED by the Board of Directors of the Omaha Public Power District that the revised Statement of Investment Policy for the Omaha Public Power District Retirement Plan, as shown on the attachment to this resolution, is hereby approved and adopted.

Docusign Envelope ID: 48157CDC-BF20-81DA-8041-767FB35BEF8F

Omaha Public Power District

BOARD OF DIRECTORS

Reporting Item

November 17, 2026

ITEM

Cass to Nebraska City Transmission Project – Route Announcement

PURPOSE

The District has finalized the route for the Cass to Nebraska City Transmission Line.

FACTS

a. OPPD has finalized the route for the Cass to Nebraska City Transmission Project.

b. A public involvement process was used in determining a route that is technically feasible while minimizing impact to landowners and the environment.

c. The line will energize in the fourth quarter of 2030.

RECOMMENDED:

Signed by:
Troy R. Via
181167221FA24AE...

Troy R. Via
Chief Operating Officer and
Vice President – Utility Operations

APPROVED FOR REPORTING TO BOARD:

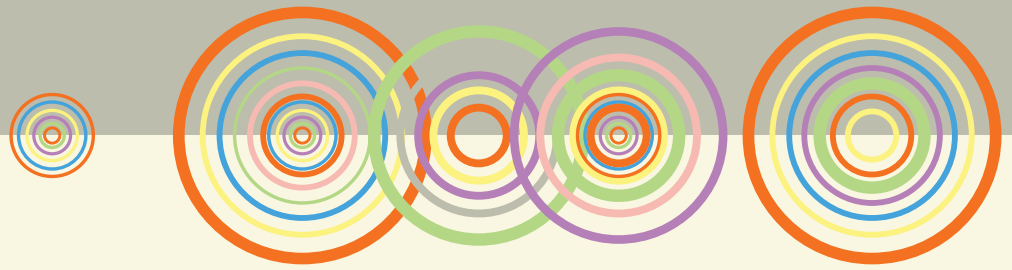
Signed by:
L. Javier Fernandez
AC399FDCE5B247E...

L. Javier Fernandez
President and Chief Executive Officer

TRV: ddb, sjh

FINAL ROUTES: TRANSMISSION

11.2026



OPPD
Omaha Public Power District

PROJECT NEED

CASS TO NEBRASKA CITY TRANSMISSION PROJECT

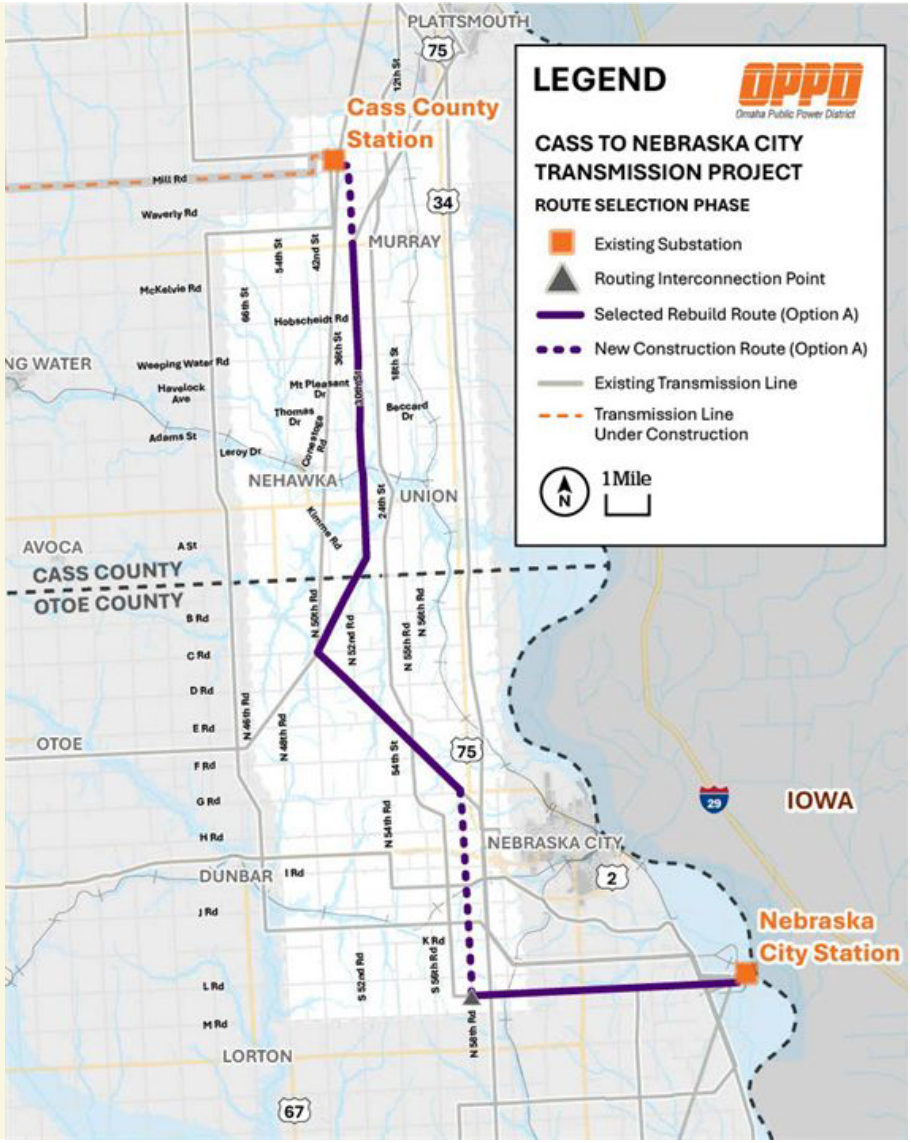
Building 33 miles of new transmission from Cass County Station to Nebraska City Station to improve power flows on our system.

SOUTHWEST POWER POOL PROJECT TO **STRENGTHEN REGIONAL SYSTEM**.

IMPROVES NORTH-SOUTH POWER FLOWS, RESULTING IN SYSTEM RESILIENCY AND RELIABILITY

ALLOWS OPPD TO TAKE ADVANTAGE OF **GENERATION GROWTH** AT CASS COUNTY STATION AND SUPPORTS INCREASED **LOAD GROWTH**

More information: oppdcommunityconnect.com/cass-to-nebraska-city



ROUTE SELECTION

Cass to Nebraska City Transmission Project

FINAL ROUTE:
Twenty-five miles of 345kV double circuit rebuilt line between Cass County Station, near Plattsmouth, and Nebraska City Station and **eight miles** of new construction.



Community supported adding new line to the existing route to **minimize disruption**



Route minimizes the need for **tree removal and easement acquisition,** although easements must be wider to accommodate double-circuit existing line



TRADEOFF: Creates higher level of **operational and construction complexity** but allows OPPD the double impact of investment – upgrade an old line **and** add a new line

PROJECT NEED

BELLEVUE RELIABILITY PROJECT

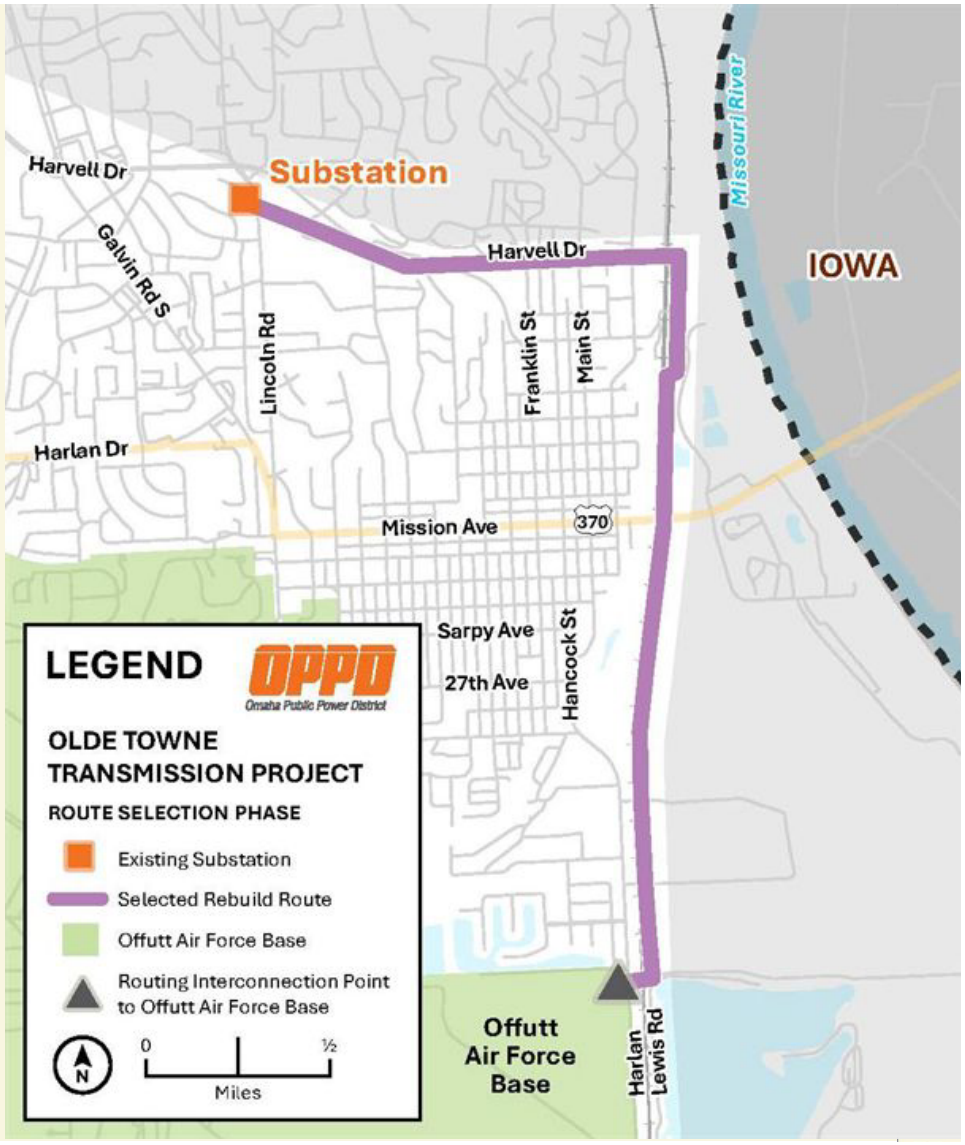
OPPD is upgrading transmission, substation and distribution systems in Bellevue to create more resilience and reliability for the community and to pave the way for planned business growth.

INVESTMENT IN INFRASTRUCTURE TO **SUPPORT GROWTH** IN SOUTHEAST BELLEVUE, INCLUDING THE NEW GOOD LIFE DISTRICT.

CREATING LONG-TERM SOLUTIONS TO **ADDRESS SYSTEM VULNERABILITIES** IDENTIFIED IN THE 2019 FLOOD.

UPGRADES AGING PART OF SYSTEM – SOME POLES AND SUBSTATIONS DATE BACK TO THE 1940S

More information: www.oppdcommunityconnect.com/bellevue



ROUTE SELECTION

Bellevue Reliability Project: Olde Towne

FINAL ROUTE:
Rebuild more than **3 miles** of 69 kV transmission line near Olde Towne Bellevue and Offutt Air Force Base to increase capacity and reliability as Bellevue continues to grow.



Minimizes disruption to Olde Towne businesses and avoids the need to navigate complex infrastructure of the area.



Design of **new structures** and improvements to the levee protects system from 500-year flood.



Reduces residential impact and provides opportunities in some cases to improve placement of existing poles and wires



WHAT'S NEXT

2027-8

PLAN and DESIGN:
Easement acquisition. Engineering design
Any distribution relocation needed as part of project

2029

CONSTRUCT
Energize Olde Town Segment Q2-3

2030

ENERGIZE
Cass to Nebraska City – Q4

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Omaha Public Power District
BOARD OF DIRECTORS

Action Item

November 17, 2026

ITEM

Acquisition of Property Rights for Utility Operations Infrastructure Projects

PURPOSE

Authorize use of eminent domain, as may be necessary, to acquire property rights for electric transmission and distribution facilities associated with the approved Cass-to-Nebraska City Transmission Project (CNCTP), ensuring a more reliable and resilient electric system while supporting growth within OPPD's service area. The project will support load growth and long-range planning of OPPD's balanced portfolio of energy resources.

FACTS

a. This requested eminent domain authorization covers property rights that need to be acquired for utility operations infrastructure to enhance system resiliency and reliability, and support load growth.

b. As part of the Cass-to-Nebraska City Transmission Project, Omaha Public Power District (OPPD) is planning to construct a new transmission line and rebuild an existing transmission line.

c. New Construction Route (north and south greenfield areas) – As part of Cass-to-Nebraska City Transmission Project, OPPD will build approximately 8 miles of new single circuit 345-kV transmission line, including 2.4 miles from Cass County Station between 24th and 42nd and Mill Road to Highway 1 in Cass County, Nebraska (north greenfield area) and approximately 5.6 miles along 58th Road to the interconnection point located between L and M Road in Otoe County, Nebraska (south greenfield area).

d. Approximately 52 permanent easements and other property rights are required for the construction, operation, and maintenance of transmission and distribution facilities for the 8-mile greenfield areas of new construction for this project.

e. Rebuild Route – OPPD will rebuild approximately 25 miles of existing transmission line as double-circuit, including 17.5 miles of 345-kV and 69-kV from Highway 1 in Cass County, Nebraska to the OPPD substation located near C Road and North 50th Street in Otoe County, Nebraska, continuing from the substation to the interconnection point located near North 58th Road and G Road in Otoe County,

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Nebraska and approximately 7.5 miles of 345-kV and 161-kV from the interconnection point to the Nebraska City Station.

f. OPPD currently expects to utilize existing property rights for the project. Additional property rights required, if any, will be determined during the design phase and acquired as needed for the construction, operation, and maintenance of transmission and distribution facilities relating to this project. Temporary easements may be required for pre-engineering survey access as well as temporary construction needs.

g. There has been Public Involvement throughout the routing and siting process. Engagement with landowners will continue through the property rights acquisition process.

h. OPPD will commence negotiations to voluntarily acquire the necessary property rights for the transmission and distribution facilities following appropriate notices being sent to landowners and after any required public hearing(s).

i. OPPD will undertake reasonable efforts to voluntarily acquire the necessary property rights through good faith negotiations. However, the use of eminent domain may be necessary if a voluntary agreement cannot be achieved between the District and landowners.

j. Management will report the filing of eminent domain actions to the Board.

k. This requested authorization extends through the duration of the Cass-to-Nebraska City Transmission Project. Any additional authorizations for the covered project(s) will be requested as needed.

ACTION

Authorization by the Board of Directors to commence eminent domain proceedings for necessary property rights not acquired voluntarily after all reasonable efforts have been made.

RECOMMENDED:

Signed by:
Peter M Fischer
D927EDF5EB00425...

Peter M. Fischer
Vice President – General Counsel

APPROVED FOR BOARD CONSIDERATION:

Signed by:
L. Javier Fernandez
AC399FDCE502A7E...

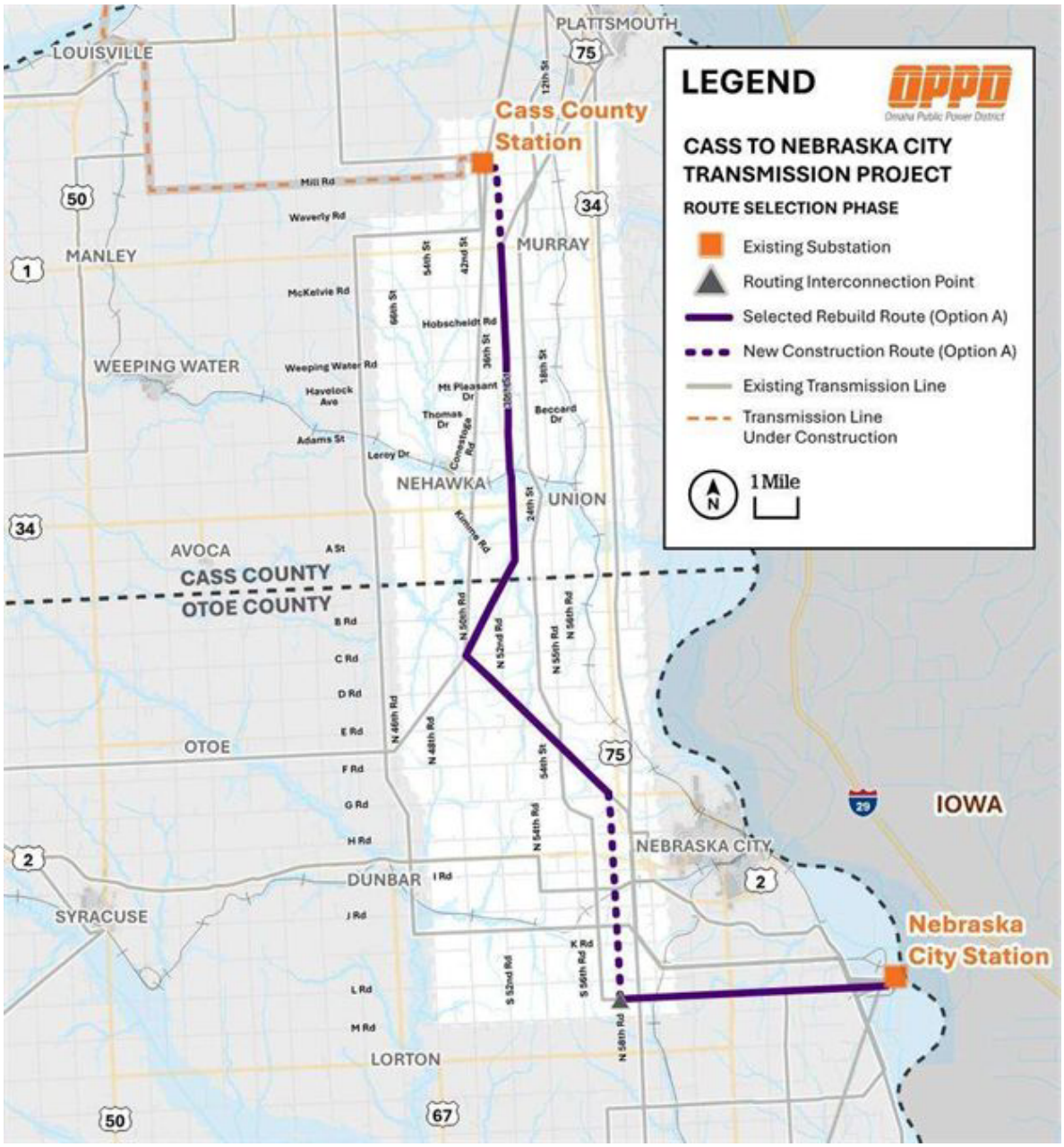
L. Javier Fernandez
President and Chief Executive Officer

PMF:jdf

Attachment: Route Maps
Resolution

Docusign Envelope ID: 736E135D-70EF-8C7B-805D-280DF2B95EA1

Final Route Map



Omaha Public Power District

Williams / Fischer

ACQUISITION OF PROPERTY RIGHTS
FOR UTILITY OPERATIONS INFRASTRUCTURE PROJECTS

RESOLUTION NO. [XXXX]

WHEREAS, the District must acquire property rights necessary for the Cass-to-Nebraska City Transmission Project (CNCTP), as such project will ensure a more reliable and resilient electric system and support growth within OPPD's service area; and

WHEREAS, the District is authorized by Nebraska Law to acquire property by eminent domain; and

WHEREAS, the use of eminent domain may become necessary to acquire property rights that cannot be obtained voluntarily through negotiations by the District.

NOW, THEREFORE, BE IT RESOLVED by the Board of Directors of the Omaha Public Power District that Management and the District's General Counsel are authorized by the Board of Directors to commence eminent domain proceedings to acquire all property rights necessary for the Project not acquired voluntarily after all reasonable efforts have been made, with this authorization extending through the duration of the Cass-to-Nebraska City Transmission Project (CNCTP).

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Omaha Public Power District

BOARD OF DIRECTORS

Reporting Item

November 17, 2026

ITEM

Bellevue Transmission Project – Olde Towne Bellevue Route Announcement

PURPOSE

The District has finalized the route for the Olde Towne Bellevue Transmission Line. The line is part of the Bellevue Reliability Project, which includes improvements in both Southeast Bellevue and Olde Towne.

FACTS

a. OPPD has finalized the route for the Olde Towne segment of the Bellevue Transmission Project.

b. A public involvement process was used in determining a route that is technically feasible while minimizing impact to landowners and the environment.

c. The line will energize in the second quarter of 2029.

RECOMMENDED:

Signed by:
Troy R. Via
18116721FA24AE...

Troy R. Via
Chief Operating Officer and
Vice President – Utility Operations

APPROVED FOR REPORTING TO BOARD:

Signed by:
L. Javier Fernandez
AC399FDCE50247E...

L. Javier Fernandez
President and Chief Executive Officer

TRV: ddb, sjh

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Omaha Public Power District
BOARD OF DIRECTORS

Action Item

November 19, 2026

ITEM

Acquisition of Property Rights for Utility Operations Infrastructure Projects

PURPOSE

Authorize use of eminent domain, as may be necessary, to acquire property rights for electric transmission and distribution facilities associated with the approved Olde Towne Transmission Project, ensuring a more reliable and resilient electric system while supporting growth within OPPD's service area. The project will support load growth and long-range planning of OPPD's balanced portfolio of energy resources.

FACTS

a. This requested eminent domain authorization covers property rights that need to be acquired for utility operations infrastructure to enhance system resiliency and reliability, and support load growth.

b. As part of the Olde Towne Transmission Project, OPPD will rebuild approximately 3.3 miles of existing 69-kV transmission line, starting south of Harvell Drive on Lincoln Road in Bellevue, Sarpy County, Nebraska and running east to the railroad, then south along the railroad to a interconnection point west of Harlan Lewis Road in Bellevue, Sarpy County, Nebraska.

c. OPPD currently expects to utilize existing property rights for the project. Additional property rights required, if any, will be determined during the design phase and acquired as needed for the construction, operation, and maintenance of transmission and distribution facilities relating to this project. Temporary easements may be required for pre-engineering survey access as well as temporary construction needs.

d. There has been Public Involvement throughout the routing and siting process. Engagement with landowners will continue through the property rights acquisition process.

e. OPPD will commence negotiations to voluntarily acquire the necessary property rights for the transmission and distribution facilities following appropriate notices sent to landowners and after any required public hearing(s).

f. OPPD will undertake reasonable efforts to voluntarily acquire the necessary property rights through good faith negotiations. However, the use of eminent

domain may be necessary if a voluntary agreement cannot be achieved between the District and landowners.

g. Management will report the filing of eminent domain actions to the Board.

h. This requested authorization extends through the duration of the Olde Towne Transmission Project. Any additional authorizations for the covered project(s) will be requested as needed.

ACTION

Authorization by the Board of Directors to commence eminent domain proceedings for necessary property rights not acquired voluntarily after all reasonable efforts have been made.

RECOMMENDED:

Signed by:
Peter M Fischer
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Peter M. Fischer
Vice President – General Counsel

APPROVED FOR BOARD CONSIDERATION:

Signed by:
L. Javier Fernandez
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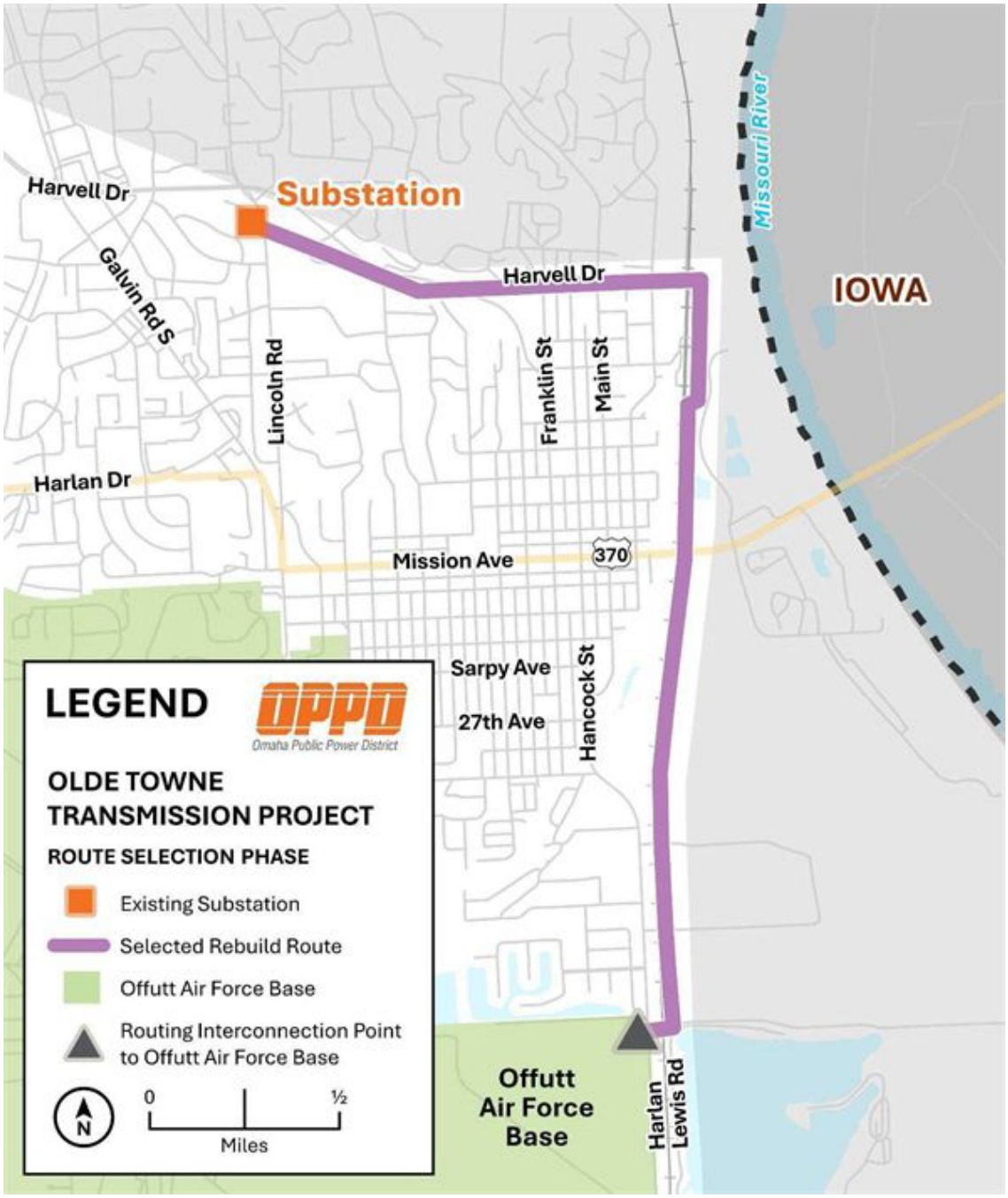
L. Javier Fernandez
President and Chief Executive Officer

PMF:jdf

Attachment: Route Maps
Resolution

Docusign Envelope ID: D1CDD7E5-267D-848D-835C-DA1B9A0F0A0F

Final Route Map
Segment 1



Williams / Fischer

ACQUISITION OF PROPERTY RIGHTS
FOR UTILITY OPERATIONS INFRASTRUCTURE PROJECTS

RESOLUTION NO. [XXXX]

WHEREAS, the District must acquire property rights necessary for the Olde Towne Transmission Project, as such project will ensure a more reliable and resilient electric system and support growth within OPPD's service area in Bellevue; and

WHEREAS, the District is authorized by Nebraska Law to acquire property by eminent domain; and

WHEREAS, the use of eminent domain may become necessary to acquire property rights that cannot be obtained voluntarily through negotiations by the District.

NOW, THEREFORE, BE IT RESOLVED by the Board of Directors of the Omaha Public Power District that Management and the District's General Counsel are authorized by the Board of Directors to commence eminent domain proceedings to acquire all property rights necessary for the Project not acquired voluntarily after all reasonable efforts have been made, with this authorization extending through the duration of the Olde Towne Transmission Project.

NEW GENERATION & TRANSMISSION UPDATE

11.17.26

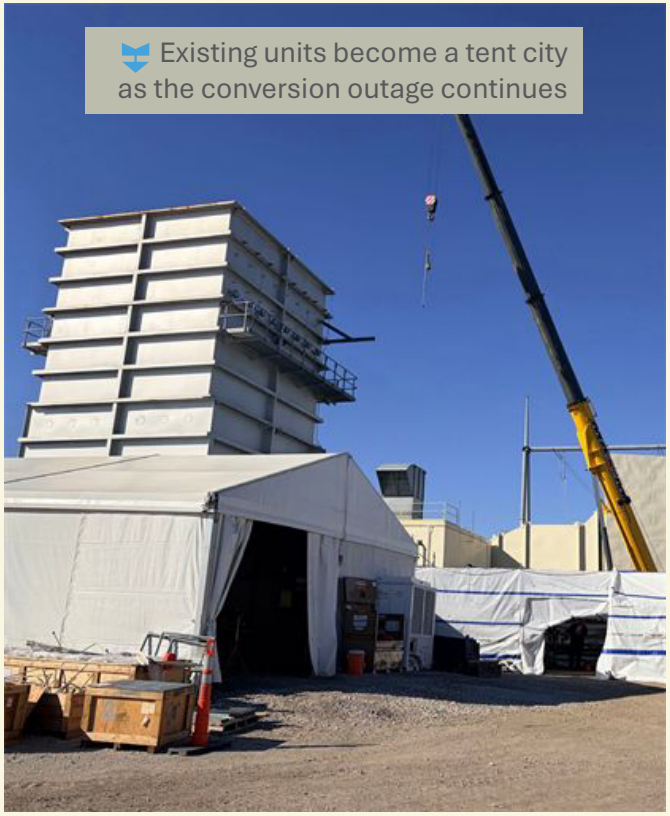
All Committee Meeting
November 17, 2026

OPPD
Omaha Public Power District

AGENDA

- Generation Update
- Transmission and Substation Update
- Renewables and Storage Update
- North Omaha Station Update

PROGRESS: CCS



Existing units become a tent city as the conversion outage continues

Budget Schedule **43% Complete**

Heat tracing



KEY WINS AND RISKS

- Concrete pours earlier this year set Kiewit up for **winter-time progress** on new generation
- Increased manhours and focus continue to address delays on dual-fuel project
- **On-site coordination** continues to stand out

Q4 2026

- Exterior and roof work completed on final water tank
- Guard shack construction for new 42nd Street entrance
- Heat tracing and insulation underway so units can operate at -30° F.
- Commissioning activities for dual-fuel, including pipe flushing, underway

Water tanks



PROGRESS: TCS

Q4 2026

KEY MILESTONES

- Electrical package has arrived
- Tank shells have been erected
- Maintenance Building exterior complete
- About 200 workers on site

Welding the stack



Tank farm continues to rise from the ground



Budget

Schedule

58% Complete

KEY WINS AND RISKS

- Five of 11 **stack sections** complete; first level of baffles
- **Schedule** continues to experience positive tailwinds
- Coordination of **GSU delivery** in mid-December

The electrical package, which includes the breakers that will power and control the new unit, was shipped on two separate trucks from Texas



TRANSMISSION & SUBSTATION

Q4 2026

UNDER CONSTRUCTION

Cass-to-Sarpy T-Line

- Complete: 100% foundations, 97% of structures, with only two monopoles & one A-frame remaining in/around CCS, and 84% of the wire.

North Douglas County T-Line

- Installation of structures and wire stringing underway for Segment 3. Construction coming for segment 2, along northern part of State Street.

Budget

Schedule

Risk



Breakers for the Cass County Station Substation



Cass to Sarpy pole construction

KEY WINS

- Public involvement has wrapped with route announcements for **three projects**
- Routing, siting and public involvement will kick off soon for the 100-plus miles of transmission for **JTIQ**
- TaSCA contractors executing on three major substation projects

RENEWABLES AND STORAGE UPDATE

BURT COUNTY SOLAR

PROJECT OVERVIEW & STATUS

2026

- Purchase Power Agreement between OPPD and Sandhills Energy finalized in May
- Early stages of construction have already started, including road work and site prep
- Design packages are in progress





Project Nameplate Capacity

- **Solar:** 250 MW

Location: Burt County, Nebraska (east of Tekamah)

Developer: Sandhills Energy

Estimated Commercial Online Date: 2029

PIERCE COUNTY ENERGY CENTER

PROJECT OVERVIEW & STATUS

Project Nameplate Capacity

- **Solar:** 420 MW
- **Energy Storage:** 170 MW

Location: Pierce County, Nebraska

Developer: NextEra Energy Resources

Estimated Commercial Online Date: Q1/Q2 2027



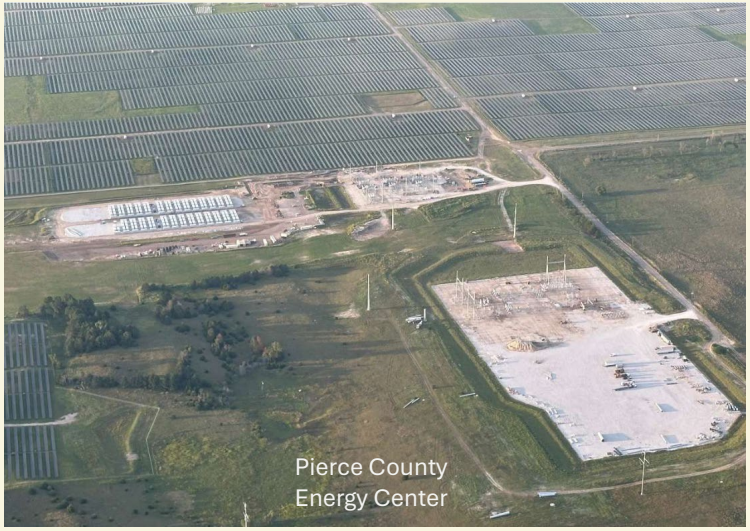


2026

Enhanced structure providing an optimized partnership among OPPD, Google and NextEra Energy Resources

Construction activity progress

- County road construction: 100%
- Site grading: 100%
- Racking installation: 100%
- Panel installation: 100%
- Substation construction: 75%
- Battery Installation: 90%
- Solar & Battery Commissioning: In progress



NORTH OMAHA STATION UPDATE

NORTH OMAHA STATION Q4 2026 UPDATE

ROAD TO NORTH OMAHA STATION TRANSITION

DEC 2025 · ✓ DONE

Grid connections approved

FERC approved the generation interconnection agreements (requested in 2020) for TCS/SBLS, a required first step.

JAN 2026 · ✓ DONE

ISP & SPP studies launched

Studies test whether the grid stays reliable following unit retirement/refueling.

WE ARE HERE · NOV 2026

Studies underway

ISP and SPP studies on track.

Next Board update: December

END OF 2026

Results to the Board

Both studies complete.

The 2026 ISP is presented to the Board.

~SPRING 2027 (EST.)

Time-sensitive board decision

Board has up to 120 days after the ISP to approve solutions.
(Board Resolution 6744)

THE PLAN

Units 1–3 Retire · Units 4–5 Refuel to Natural Gas (no longer available during winter months)
ISP and SPP studies will inform of grid investments that may be needed to enable NOS retirement/refueling

TCS: Turtle Creek Station · SBLS: Standing Bear Lake Station · ISP: Integrated System Plan · SPP: Southwest Power Pool

QUESTIONS?

Docusign Envelope ID: 792158ED-7C70-8D97-812F-2809E1BB806B

Omaha Public Power District
BOARD OF DIRECTORS

Board Action

November 17, 2026

ITEM

Interlocal Agreements for Transmission Operator (TOP) Services with Hastings Utilities and Grand Island Utilities

PURPOSE

Authorize OPPD to enter into Interlocal Agreements with Hastings Utilities (HU) and Grand Island Utilities (GRIS) for continued Transmission Operator services.

FACTS

a. OPPD has provided Transmission Operator (TOP) services to HU and GRIS since 2017, supporting reliable transmission system operations and compliance with applicable reliability requirements.

b. GRIS has requested transitioning its current TOP Services Agreement to an Interlocal Agreement to align with updated accounting and administrative practices. HU has similarly requested an Interlocal Agreement structure to provide a long-term framework.

c. Interlocal Agreements, authorized under Nebraska law, provide a stable and flexible framework for ongoing cooperation between public power entities while preserving amendment and termination rights.

d. The transition to Interlocal Agreements does not change OPPD's operational responsibilities. OPPD will continue providing transmission operations, reliability coordination, and applicable TOP compliance services for both utilities.

e. Benefits of the Interlocal Agreements include:

- Continued compliance with North American Electric Reliability Corporation (NERC), Federal Energy Regulatory Commission (FERC), Midwest Reliability Organization (MRO), and Southwest Power Pool (SPP) reliability requirements.
- Long-term continuity of critical transmission reliability services.
- Reduced administrative burden and contract renewal requirements for participating utilities.

- Efficient utilization of OPPD's existing transmission operations infrastructure and compliance programs.
- Continued recovery of costs associated with providing TOP services.
- Strengthened public power partnerships and regional reliability coordination.

RECOMMENDED:

Signed by:
Troy R. Via
10110721FA24AE...

Troy R. Via
Chief Operating Officer and
Vice President – Utility Operations

APPROVED FOR REPORTING TO BOARD:

Signed by:
L. Javier Fernandez
AC399FDCE56247E...

L. Javier Fernandez
President and Chief Executive Officer

Docusign Envelope ID: 792158ED-7C70-8D97-812F-2809E1BB806B

Omaha Public Power District
BOARD OF DIRECTORS

Williams/Via

DRAFT

RESOLUTION NO. XXXX

WHEREAS, the District has provided transmission operator services to Hastings Utilities and Grand Island Utilities for several years; and

WHEREAS, Hastings Utilities and Grand Island Utilities desire to continue utilizing the services of the District for this function but wish to do so using an interlocal agreement pursuant to the Nebraska Interlocal Cooperation Act; and

WHEREAS, the District has negotiated interlocal agreements with both utilities; and

WHERAS, the Interlocal Cooperation Act requires the District's Board of Directors to approve such interlocal agreements.

NOW, THEREFORE, BE IT RESOLVED, that the Board of Directors of the Omaha Public Power District hereby authorizes and directs Management of the District to execute interlocal agreements with the City of Hastings, Nebraska, dba Hastings Utilities and the City of grand Island, Nebraska, dba Grand Island Utilities, to allow the District to perform transmission operator functions for those two utilities as outlined in the interlocal agreements.

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Omaha Public Power District
BOARD OF DIRECTORS

Action Item

November 17, 2026

ITEM

Award RFP No. 6263 “House Service Transformer”

PURPOSE

Board of Directors’ authorization to reject all bids received for RFP No. 6263, and for the District to enter into a negotiated multi-year contract for the procurement of a spare House Service Transformer to support sparing strategies.

FACTS

a. House Service Transformers are required to support plant operations. This contract will initially procure one (1) House Service Transformer to serve as a spare for the existing House Service Transformers at Nebraska City Station Unit 1 and enhance plant reliability.

b. Desired contract will be for an initial term of one (1) year with the option to renew up to four (4) additional one (1) year terms with an acceptable escalation/de-escalation formula based on identified indices.

c. Three (3) proposals were received; zero (0) are legally responsive and two (2) are technically responsive.

d. Desired delivery of the initial House Service Transformer is May 2030.

ACTION

Authorization by the Board to reject all bids received for RFP No. 6263, “House Service Transformer” and allow District Management to enter into a negotiated contract.

RECOMMENDED:

Signed by:
Troy R. Via
181TB7221FA24AE...
Troy R. Via
Chief Operating Officer and Vice President – Utility Operations

APPROVED FOR REPORTING TO BOARD:

Signed by:
L. Javier Fernandez
AC399FDCE5B247E...
L. Javier Fernandez
President and Chief Executive Officer

Attachment: Analysis of Proposals
Tabulation of Bids

Docusign Envelope ID: 3FB314E4-DD5E-8B3F-836F-EB320DE91B90

Legal Opinion
Resolution

Docusign Envelope ID: 3FB314E4-DD5E-8B3F-836F-EB320DE91B90

Omaha Public Power District

MEMORANDUM

Date: November 10, 2026 UO-2026-018

From: S.A. Eidem

To: T. R. Via

Subject: RFP No. 6263 House Service Transformer Analysis of Proposals

1.0 GENERAL

RFP No. 6263 was advertised for bid on August 13, 2026.

RFP No. 6263 provides the opportunity to purchase House Service Transformers as specified in RFP No. 6263 for an initial term of one (1) year with the option to renew up to four (4) additional one (1) year terms pursuant to the escalation/de-escalation provisions. OPPD will initially procure one (1) House Service Transformer, which will serve as a spare for two (2) existing House Service Transformers at Nebraska City Station Unit 1 with a desired delivery date of May 2030. These transformers are vital for proper and reliable unit operation, so a ready spare strategy is prudent based upon long lead times.

One (1) Letter of Clarification (LOC) was issued. No addendums were issued.

Proposals were requested and opened at 1:00 p.m., C.D.T., Thursday, October 15, 2026.

Engineer's Estimate was $ 3,750,000.00.

Three (3) proposals were received, which are summarized in the table below:

Bidder	Lump Sum Firm Price	Legally Responsive	Technically Responsive
Howard Industries Inc.	$2,270,000	No	Yes
Virginia Transformer Corp	$1,840,297	No	No
WEG Transformer USA	$2,462,680	No	Yes

2.0 COMPLIANCE WITH CONTRACT TERMS AND GENERAL REQUIREMENTS

OPPD's legal counsel deemed that the bids received from Howard Industries Inc. ("Howard"), Virginia Transformer Corp ("Virginia"), and WEG Transformer USA ("WEG") were all legally non-responsive with most notable deficiencies described below:

Howard submitted significant redlines to the District's standard Master Procurement Agreement ("MPA"), many of which materially differ from the RFP's stated requirements and, taken as a whole, would materially shift risk to the District. Further, Howard seeks to apply a price adjustment mechanism, contrary to the RFP's firm pricing requirement. Howard also states that conflicts within the MPA may be negotiated prior to order placement, which is not permitted under the sealed-bid process.

444 S. 16th St.
Omaha, NE 68102

Docusign Envelope ID: 3FB314E4-DD5E-8B3F-836F-EB320DE91B90

Virginia did not accept or redline the District's standard MPA. Instead, it conditioned its bid on its own standard terms, substituting Virginia law and binding arbitration in Roanoke for the MPA's Nebraska governing law and Douglas County venue, capping liability, disclaiming implied warranties, and waiving liquidated damages upon broad triggers. Further, its price is not firm despite being labeled as such. Per its proposal, Virginia reserves the right to pass through cost increases whenever an "abnormal" increase raises the unit cost by two percent (2%) or more, and to apply additional index-based and tariff/surcharge adjustments. Finally, its bid is valid only through November 13, 2026, short of the RFP's mandatory ninety (90) day period.

WEG did not accept or redline the District's standard MPA. Instead, it bid on a different, previously executed agreement from 2024 plus its own commercial terms (notably, modified payment terms, warranty limitations, cancellation and suspension charges, and scope exclusions). Further, WEG's pricing is subject to its own adjustment methodology, contrary to the RFP's firm price requirement. Finally, WEG's bid is valid only through November 12, 2026, short of the ninety (90) day minimum.

3.0 COMPLIANCE WITH TECHNICAL REQUIREMENTS

The proposals received from both Howard Industries Inc., and WEG Transformer USA were deemed technically responsive. The proposal received from Virginia Transformer Corp was deemed technically non-responsive largely because the transformer drawing that was submitted with the bid did not include everything that was specified

4.0 RECOMMENDATION

On the basis of compliance with the legal and technical requirements, it is recommended that the three (3) proposals received for RFP No. 6263 "House Service Transformer" be rejected by the Board of Directors and that District Management be authorized to enter into a negotiated contract.



Scott A. Eidem, P.E.
Director Generation Engineering
Utility Operations

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TABULATION OF BIDS Opened at 1:00 p.m., CST Thursday, October 15, 2026, in Omaha, Nebraska Anticipated Award Date November 20, 2026 ENGINEER'S ESTIMATE $3,750,000.00	REQUEST FOR PROPOSAL NO. 6263 House Service Transformer Page 1 of 1	Signed by: Steve Palmer C171422F76EE422... Director Supply Chain Management Signed by: Tony Autry Compiled by and Certified Correct

BID ITEM	BIDDER'S NAME & ADDRESS Virginia Transformer Corp 220 Glade view Drive, NE Roanoke, VA 24012	BIDDER'S NAME & ADDRESS Howard Industries, Inc. 3225 Pendorff Rd Laurel, MS 39440	BIDDER'S NAME & ADDRESS WEG Transformer USA 6350 Bluff Road Washington, MO 63090
	SUPPLIER'S BID	SUPPLIER'S BID	SUPPLIER'S BID
1. Price Proposal Lump Sum Firm Price (Contract Price) to perform all Work as specified.	$1,840,297.00	$2,270,000.00	$2,462,680.00
2. Desired Delievery Date Date: May 13, 2030	Guaranteed Delivery Date 55-60 Weeks from Order Acknowledment	Guaranteed Delivery Date May 13 ,2030	Guaranteed Delivery Date 140 Weeks ARO

Docusign Envelope ID: 3FB314E4-DD5E-8B3F-836F-EB320DE91B90

Amelia V. Prickett
ATTORNEY
402.978.5264
aprickett@fraserstryker.com
fraserstryker.com

October 28, 2026

Omaha Public Power District
1919 Aksarben Drive
Omaha, NE 68106

RE: Request for Proposal No. 6263 – House Service Transformer

Ladies and Gentlemen:

We have reviewed the three (3) proposals received in response to the Omaha Public Power District ("District") RFP No. 6263 as submitted by Howard Industries, Inc. ("Howard"), Virginia Transformer Corp/Georgia Transformer ("Virginia"), and WEG Transformers USA ("WEG"), and provide the following legal opinion. Each proposal is legally non-responsive and should not be considered by the Board for award. Though non-exhaustive, the most notable deficiencies are briefly described below.

Howard Industries, Inc.
Howard submitted significant redlines to the District's standard Master Procurement Agreement ("MPA"), many of which materially differ from the RFP's stated requirements and, taken as a whole, would materially shift risk to the District. Further, Howard seeks to apply a price adjustment mechanism, contrary to the RFP's firm pricing requirement. Howard also states that conflicts within the MPA may be negotiated prior to order placement, which is not permitted under the sealed-bid process.

Virginia Transformer Corp
Virginia did not accept or redline the District's standard MPA. Instead, it conditioned its bid on its own standard terms, substituting Virginia law and binding arbitration in Roanoke for the MPA's Nebraska governing law and Douglas County venue, capping liability, disclaiming implied warranties, and waiving liquidated damages upon broad triggers. Further, its price is not firm despite being labeled as such. Per its proposal, Virginia reserves the right to pass through cost increases whenever an "abnormal" increase raises the unit cost by two percent (2%) or more, and to apply additional index-based and tariff/surcharge adjustments. Finally, its bid is valid only through November 13, 2026, short of the RFP's mandatory ninety (90) day period.

WEG Transformers USA
WEG did not accept or redline the District's standard MPA. Instead, it bid on a different, previously executed agreement from 2024 plus its own commercial terms (notably, modified payment terms, warranty limitations, cancellation and suspension charges, and scope exclusions).

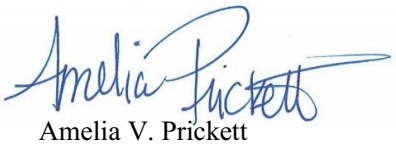
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Further, WEG's pricing is subject to its own adjustment methodology, contrary to the RFP's firm price requirement. Finally, WEG's bid is valid only through November 12, 2026, short of the ninety (90) day minimum.

Conclusion

The proposals of Howard, Virginia, and WEG are legally non-responsive and none may be considered by the Board for award. Because no responsive bids were received, Neb. Rev. Stat § 70-637(5)(a) permits the District to procure the equipment by direct negotiation. Therefore, we recommend that the Board determine that no responsive bids were received under RFP No. 6263 and authorize the District to negotiate a contract directly with a qualified supplier.

Best,



Amelia V. Prickett
FOR THE FIRM

#3638027

Williams/Via

RESOLUTION NO. XXXX

WHEREAS, sealed bids were requested and advertised, as required by law, for the following:

REQUEST FOR PROPOSAL (RFP) NO.6263
HOUSE SERVICE TRANSFORMER

WHEREAS, bids were received and opened at the time and place mentioned in the published notices and the Director – Supply Chain Management supervised the tabulations, which have been submitted to this Board; and

WHEREAS, the Board of Directors has carefully considered the bids submitted, as well as the recommendations of the District's Management and General Counsel; and

WHEREAS, Section 70-637 of the Nebraska Revised Statutes authorizes the District's Board of Directors to reject proposals if they are not responsive to the Request for Proposal, and to authorize Management to pursue a negotiated contract; and

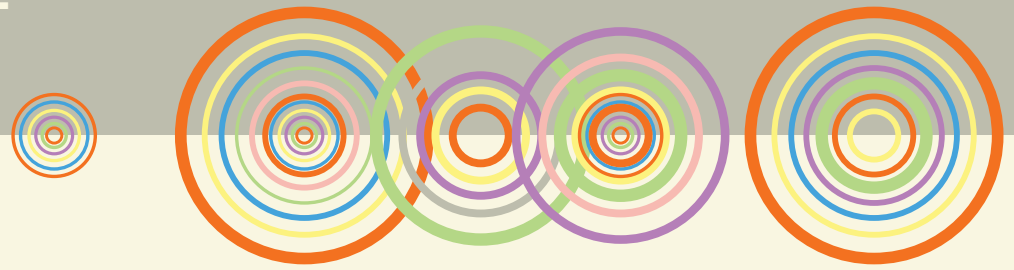
WHEREAS, the Board of Directors concurs with management's recommendation that all the proposals for RFP No. 6180 are legally or technically non-responsive.

NOW, THEREFORE, BE IT RESOLVED by the Board of Directors of the Omaha Public Power District that all proposals received in response to Request for Proposal No.6263 are rejected and Management is authorized to negotiate and enter into a multi-year contract for the procurement of a pare House Service Transformer to support sparing strategies, subject to review and approval of the final contract(s) by the District's General Counsel.

DRAFT

BOARD OF DIRECTORS 11.17.26 COMMITTEE MEETING

RFP#6263 – NC1 SPARE HOUSE SERVICE TRANSFORMER



OPPD
Omaha Public Power District

NC1 SPARE HOUSE SERVICE TRANSFORMER

A HOUSE SERVICE TRANSFORMER IS USED AT A GENERATION FACILITY TO STEP DOWN A TRANSMISSION LEVEL VOLTAGE TO A LOWER VOLTAGE, WHICH FEEDS THE GENERATION FACILITY'S AUXILIARY EQUIPMENT AND BUILDING LOADS.





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Omaha Public Power District
BOARD OF DIRECTORS

Reporting Item

November 17, 2026

ITEM

Nuclear Oversight Committee Report

PURPOSE

The Nuclear Oversight Committee provides regular oversight of items related to Fort Calhoun Station (FCS).

FACTS

In addition to maintaining safe and secure dry cask storage of used nuclear fuel, the project team continues to advance along the site's license-termination path.

a. The project achieved substantial completion on September 30th with the completion of on-site surveys and samples.

b. The focus now is on completion of off-site laboratory analysis and final site survey documentation. Currently:
    a. The first two survey unit phases have been approved by the Nuclear Regulatory Commission (NRC).
    b. Five of the six survey unit phases have been submitted for NRC review.
    c. The final survey unit package is expected to be submitted in early 2027.

c. Following completion and submittal of all survey data, a License Amendment Request (LAR) will be submitted for NRC approval which includes the final analysis and verification of site radiological release criteria leading to subsequent release of the site for unrestricted use as best serves OPPD, our customer-owners, and our communities.

RECOMMENDED:

Signed by:
Troy R. Via
18116Z221FA24AE...

Troy R. Via
Chief Operating Officer and Vice President – Utility Operations

APPROVED FOR REPORTING TO BOARD:

Signed by:
L. Javier Fernandez
AC399FDCE56247E...

L. Javier Fernandez
President and Chief Executive Officer

TRV:tsu

FCS DECOMMISSIONING UPDATE

FINISHING STRONG

- Substantial Completion achieved September 30th, 2026
- Documentation Status
  - Survey Unit phases 1 & 2 reviewed & approved by NRC
  - Phases 3, 4 and 5 have been submitted
  - Phase 6 (final) submittal is anticipated in early 2027
  - License Amendment Request submittal is anticipated by March 2027
- Final NRC review and subsequent release of the site for unrestricted use is anticipated 3rd - 4th Quarter 2027
- Future site use is open to whatever best serves the District, our customer-owners, and the surrounding communities



Then and Now



THANK YOU to all those who built, operated, maintained, protected, and decommissioned Fort Calhoun Station

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Omaha Public Power District
BOARD OF DIRECTORS

Reporting Item

November 17, 2026

ITEM

Severance Agreements – Fort Calhoun Station Decommissioning

PURPOSE

Report on Severance Agreements executed due to decommissioning of Fort Calhoun Station

FACTS

a. Omaha Public Power District's Board of Directors voted on June 16, 2016, to cease operations at Fort Calhoun Station.

b. Omaha Public Power District offers a severance program (for the purposes of Fort Calhoun Station Decommissioning) for exempt employees who stay with the district through their layoff date in exchange for a release of claims. IBEW Local 763, IBEW Local 1483, and IAWAM Local 31 entered into a Memoranda of Understanding with OPPD which includes the same severance program.

c. As of October 1, 2026, four additional employees have been separated from OPPD as a result of FCS Decommissioning and separation agreements have been executed.

d. These severance agreements involved payments that exceed $50,000 and therefore may be subject to the requirement for reporting settlement agreements under Section 84-713 of the Nebraska Revised Statutes. These agreements are referenced on the attachment.

e. These severance agreements are available for inspection in the office of the Corporate Secretary.

ACTION

Reporting item

RECOMMENDED:

Signed by:
Joni Wheeler
320840261B344300...
Joni Wheeler
Vice President, Human Capital

APPROVED FOR REPORTING TO BOARD:

Signed by:
L. Javier Fernandez
AC398FDCE68247E...
L. Javier Fernandez
President and Chief Executive Officer

Attachments: List of October 2026 Severance Agreements Exceeding $50,000

Attachment
List of October 2026 Severance Agreements Exceeding $50,000

Employee Information as of October 1, 2026	Total Severance
Maintenance Program Specialist (Utility Operations)	$78,509.89
Supervisor Radiation Protection (Utility Operations)	$117,314.29
Principal Regulatory Specialist (Utility Operations)	$137,920.46
Assistant Plant Manager Ops (Utility Operations)	$214.238.27

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Omaha Public Power District
BOARD OF DIRECTORS

Action Item

November 17, 2026

ITEM

SD-11: Economic Development Monitoring Report

PURPOSE

To ensure full Board review, discussion and acceptance of SD-11: Economic Development Monitoring Report.

FACTS

a. The first set of Board policies was approved by the Board on July 16, 2015. A second set of Board policies was approved by the Board on October 15, 2015.

b. Each policy was evaluated and assigned to the appropriate Board Committee for oversight of the monitoring process.

c. The Customer and Public Engagement Committee is responsible for evaluating Board Policy SD-11: Economic Development.

d. The Customer and Public Engagement Committee has reviewed the SD-11: Economic Development Monitoring Report, as outlined on Exhibit A, and is recommending that OPPD be found to be sufficiently in compliance with the policy as stated.

ACTION

The Customer and Public Engagement Committee recommends Board approval of the 2026 SD-11: Economic Development Monitoring Report.

RECOMMENDED:

Signed by:
Timothy D. McAreavey
D993182BA1BC42E...
Timothy D. McAreavey
Vice President, External Relations and Chief Customer & Public Engagement Officer

APPROVED FOR BOARD CONSIDERATION:

Signed by:
L. Javier Fernandez
AC398FDCE58247E...
L. Javier Fernandez
President and Chief Executive Officer

Attachments:
Exhibit A – Monitoring Report
Resolution

Exhibit A

SD-11: ECONOMIC DEVELOPMENT

11.17.26



Tim McAreavey
Vice President, External Relations and
Chief Customer & Public Engagement Officer

OPPD
Omaha Public Power District

SD-11: ECONOMIC DEVELOPMENT

Economic prosperity is foundational to cultivating vibrant and thriving communities we serve.

OPPD's strategic leadership and active participation in regional economic development initiatives will create a favorable environment to attract new business and help existing business customers to expand and support workforce and community needs. OPPD's economic development strategy will adapt and change to maximize value for the region as the utility and the region's advantages and opportunities evolve.

Therefore, OPPD shall exercise leadership and participate in economic development to:



Attract, retain & expand businesses



Serve as a community leader and trusted partner to organizations and leaders on local, regional and statewide initiatives and activities in economic development, including workforce and community needs



Offer and promote effective tools, resources, programs, products, services and rates to educate our business customer owners and support economic growth, sustainability, cost savings and/or vitality



Assist with site development and marketing to plan or best optimize our energy system for businesses and industrial customer-owners

ECONOMIC DEVELOPMENT IS THE INTENTIONAL PRACTICE OF IMPROVING A COMMUNITY'S ECONOMIC WELL-BEING AND QUALITY OF LIFE.

OPPD supports the ecosystem in all facets through a power lens while delivering essential infrastructure and services – the lifeblood that powers thriving communities.



Source: International Economic Development Council

COMPARING OURSELVES AGAINST OTHER AREAS: CHALLENGES + OPPORTUNITIES

Key Economic Development Challenges

- Site development, including infrastructure readiness, utility constraints (power included) and availability of sites for development
- Workforce availability
- Competition from peer states

Key Economic Development Opportunities

- OPPD is increasingly viewed as a critical regional economic development partner - site readiness and infrastructure planning are becoming competitive advantages
- Increasing workforce competitiveness to support long-term regional prosperity
- Future growth will require enhanced planning, policy and modernizing economic development tools









Attract, retain & expand businesses



- $30 million capital investment by business
- Retention of existing jobs and creation of 200+ new engineering, manufacturing positions in the region

CAPITAL INVESTMENT FROM INDUSTRY CREATES COMMUNITY IMPACT

Facilitated outcomes among business community to bring:

$272M
Direct Capital Investment

$445M
Total Economic Impact

NEW OPPORTUNITIES IN COMMUNITY

537
Direct Jobs Landed

1,368
Overall Jobs (Total Effect)

$267M
537 direct jobs bring additional production of goods and services

$455M
1,368 overall new jobs bring additional production of goods and services

1,719
new additional jobs due to capital investment

Source: University of Nebraska-Omaha 2026 OPPD Economic Impact Analysis

Attract, retain & expand businesses

WE'RE SERVING CUSTOMER GROWTH AND NEED TO SERVE MUCH MORE

- Macro trends continue to drive unprecedented demand, including for OPPD
- Rising demand requires significant near- and long-term planning
  - Active project requests continue to signal substantial future load growth across multiple sectors
  - Regional corridors and target industry focus are putting upward pressure on near- and mid-term needs (i.e. inland ports, AgWorks, etc.)
- Businesses and communities seeking answers and continuous solutions
- OPPD committed to delivering solutions that keep the region competitive, resilient and future-ready
- We are growing while keeping to our mission of reliability and affordability

Reliability

2nd

Ranked in the nation

18% **Commercial Rates**

25% **Industrial Rates**

Below national average

Serve as a community leader and trusted partner

to organizations and leaders on local, regional and statewide initiatives and activities in economic development, including workforce and community needs

LEADING AND PARTNERING ON ECONOMIC & COMMUNITY DEVELOPMENT PLANNING



Leading and serving on dozens of boards and key partner on community initiatives. Supported strategic planning efforts as Chair of Grow Sarpy and Chair of Nebraska City Area Economic Development Corporation. Co-facilitated Nebraska Chamber's Go Big Future Momentum Forum and participated in task force for development of Omaha Competes with Greater Omaha Chamber.

We Make Omaha



Serving on steering, economic development and land use committees to shape City of Omaha's We Make Omaha comprehensive plan. Supported comprehensive plans for City of Yutan, Sarpy County, Nemaha County and City of Bellevue.

Nebraska Association of County Officials

6 REGIONS One Nebraska

Serving on the Nebraska Association of County Officials (NACO) Land Use Committee to provide information, planning tools and regulatory considerations that support local decisions reflecting community priorities, applicable laws and sound planning practices. Supporting 6 Regions One Nebraska and facilitating discussion on challenges communities face with infrastructure, including water and waste-water systems.

CONNECTING ENTREPRENEURIAL COMMUNITIES



Presenting at Connecting Entrepreneurial Communities through Rural Prosperity Nebraska's conference that showcases rural innovation with practical strategies to foster entrepreneurship, support small businesses, and drive long term economic growth. Partnering with MAPA and local leaders to learn best practices from other metro regions to further community and economic development planning.

Serve as a community leader and trusted partner











LEAD, ADVOCATE AND PARTNER ON WORKFORCE + COMMUNITY NEEDS

Education

Supporting Career Fairs and Partnering on STEM Events

- ~50 events; engage with 5000+ students
- Marshmallow Challenge and Girls in Engineering

Continuing Connect the Dots and Mentoring Opportunities

- 4 rural area events; partnered with University of Nebraska Extension to engage 500+ students
- ~20 employees active mentors with ACE, Big Brothers Big Sisters, and TeamMates

Supporting workforce development through regional and statewide plans

Basic Needs & Community Betterment

Leading and Partnering with Community Organizations

- Raised more than $500K through Walk for Warmth, Month of Giving and Swigart events to support Greener Together Program, EAP (serving 600+ households) and provide scholarships
- Employees volunteer for Shine Bright (pack hygiene kits) and Day of Caring

ZL1

Co-hosting Community Resource Fairs

- Partnered with 31 non-profits in North Omaha, Louisville and LaVista to serve ~2500 households with ~$825K in bill relief

Leading and Partnering with Habitat

- Rock the Block in North Omaha + Otoe County
- New OPPD led partnership helps fast track homes for those in need - 40 lots in North Omaha neighborhoods

Offer and promote effective tools, resources, programs, products, services and rates

to educate our business customer owners and support economic growth, sustainability, cost savings and/or vitality

PROMOTING TOOLS AND RESOURCES TO SUPPORT ECONOMIC GROWTH AND VITALITY

SizeUp

Objective:
Provide tools and resources to educate small business customers

Outcomes:

- Provided 10,802 reports for business owners and entrepreneurs with almost 566 unique user visits
- Entrepreneurial ecosystem leaders leverage tool for small and emerging businesses
- Hosted a training session with eight small business development partner organizations.



SourceLink

Objective:
Connect businesses and entrepreneurs with resources to support economic growth

Outcomes:

- Cumulation of services: Website utilization totals 44,617 visits, resulting in 1,169 Personal Action Plans created and 14,868 direct referrals to partner organizations
- The Resource Navigator tool generated 8,181 searches and more than 695,752 total online referrals, with a total of 4,740 statewide events posted to the ecosystem calendar since OPPD became a partner

PROVIDING OFFERINGS TO SUPPORT COST SAVINGS & SUSTAINABILITY

Offer and promote effective tools, resources, programs, products, services and rates

to educate our business customer owners and support economic growth, sustainability, cost savings and/or vitality

NEBRASKA
DEPT. OF ECONOMIC DEVELOPMENT

SELECT GREATER OMAHA



Business Retention + Expansion Program

Objective:
Partner with economic development organizations to conduct business visits to identify opportunities to support customers

Outcomes:
- Completed 11 energy audits helping businesses identify cost savings and efficiencies
- Identified 9 business expansion project opportunities and connected companies with support services and resources

Greener Together Program

Objective:
Promote sustainability and savings through funding community projects (energy efficiency and renewable projects)

Outcomes:
- Over the next 12 months, Google has pledged $6 million to OPPD and the United Way
  - $875,000 has been designated to support Greener Together projects



Assist with site development and marketing

to plan or best optimize our energy system for businesses and industrial customer-owners



PLANNING WITH COMMUNITIES FOR SITE READINESS AND FUTURE GROWTH

GREATER OMAHA CHAMBER AWARDED $480,000 EDA GRANT TO PREPARE SITES FOR MAJOR EMPLOYERS





Site Readiness

Objective:

Assess site readiness on sites statewide, including infrastructure capacities, and provide expertise to advance site readiness

Outcome:

Partnering with state and local leaders to advance site readiness efforts such as LB644, Greater Omaha Economic Development Partnership GO Ready Site Program, including support of U.S. Economic Development Administration Grant

Planning Long-Term Growth

Objective:

Identify and assess sites to plan for long-term key growth areas with external partners and create opportunity for future business and industry

Outcome:

Bridging the gap between internal planning teams and external stakeholders to develop long term infrastructure strategy for industrial sites. Serve on Nebraska Chamber's site readiness working group to formalize policy and planning strategy

PLANNING FOR TOMORROW STARTS TODAY

OPPD
Omaha Public Power District

Leader, partner and stakeholder of policy and planning today to further economic growth of the region and in turn ensuring our communities can thrive and prosper

- Statewide energy studies
- Local regulations education and advocacy toward common goals for zoning and siting
- Site development and readiness
- Nuclear siting study and consortium
- Economic development programming and planning

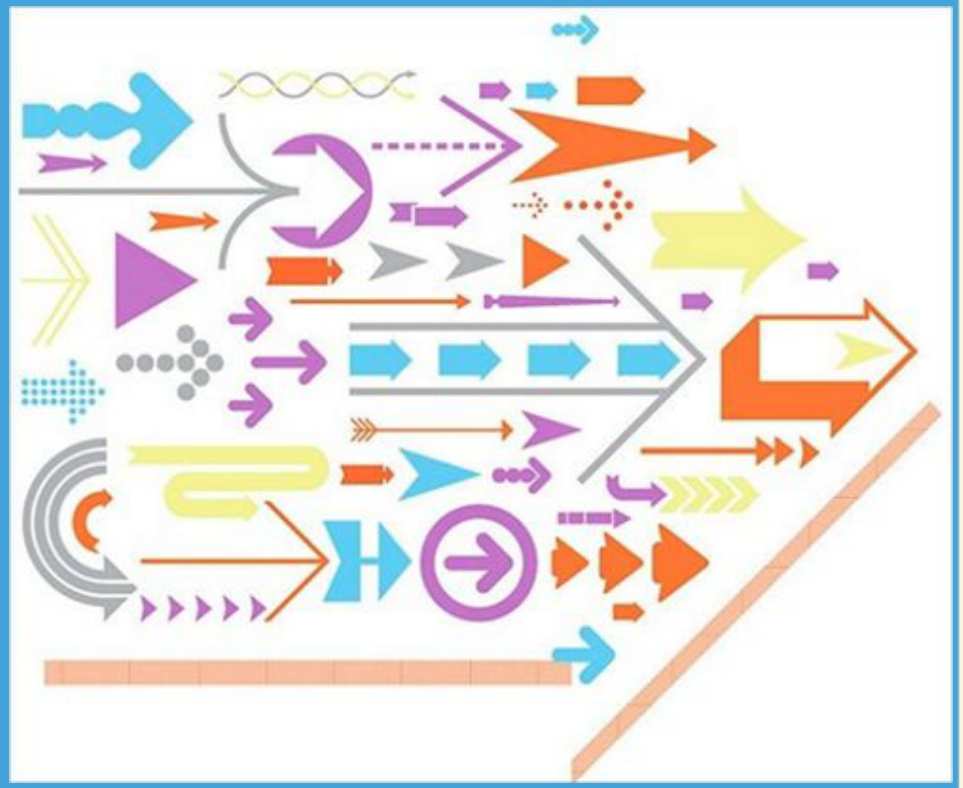


RECOMMENDATION

The Customer and Public Engagement Committee has reviewed and accepted this Monitoring Report for SD-11: Economic Development and recommends that the Board finds OPPD to be sufficiently in compliance with Board Policy SD-11.

Any reflections on

- What emerging stakeholder expectations or trends, if any, could impact our strategic direction?



Howard/McAreavey

RESOLUTION NO. XXXX

WHEREAS, the Board of Directors has determined it is in the best interest of the District, its employees, and its customer-owners to establish written policies that describe and document OPPD's corporate governance principles and procedures; and

WHEREAS, each policy was evaluated and assigned to the appropriate Board Committee for oversight of the monitoring process; and

WHEREAS, the Board's Customer and Public Engagement Committee (the "Committee") is responsible for evaluating Board Policy SD-11: Economic Development on an annual basis. The Committee has reviewed the 2026 SD-11: Economic Development Monitoring Report and finds OPPD to be sufficiently in compliance with the policy as stated.

NOW, THEREFORE, BE IT RESOLVED that the Board of Directors of Omaha Public Power District hereby accepts the 2026 SD-11: Economic Development Monitoring Report, in the form as set forth on Exhibit A attached hereto and made a part hereof, and finds OPPD to be sufficiently in compliance with the policy as stated.

DRAFT

Omaha Public Power District
BOARD OF DIRECTORS

Board Action

November 17, 2026

ITEM

Appointment of Interim President and Chief Executive Officer

PURPOSE

Approval of the appointment and compensation of Troy R. Via as Interim President and Chief Executive Officer, effective December 27, 2026.

FACTS

a. L. Javier Fernandez, President and Chief Executive Officer (CEO), has announced that he will step down from his position effective December 31, 2026.

b. In accordance with Board Policy GP-3: Board Job Description, the Board is responsible for the hiring and appointment, as well as compensation and benefit approval, of the CEO.

c. The Governance Committee recommends the appointment of Troy R. Via, currently Chief Operating Officer and Vice President Utility Operations, as Interim President and CEO, and presented its recommendation at the November 17, 2026 all-committee meeting.

d. Mr. Via joined OPPD in September 2013 as Director Energy Marketing and Trading, was appointed Vice President Energy Delivery in 2018, and in 2021 became Chief Operating Officer and Vice President Utility Operations, leading energy delivery and generation operations. Before joining OPPD, he held roles in power trading at Dominion Resources and Aquila Energy. Mr. Via holds a bachelor's degree from the University of Central Missouri with a focus in finance.

e. The interim appointment is intended to provide leadership continuity and stability while the Board conducts a separate search and selection process for the permanent President and CEO.

f. The Governance Committee recommends that Mr. Via's annualized interim compensation be established at 80% of the midpoint of the salary range for the President and Chief Executive Officer position, in recognition of the additional responsibilities associated with the interim assignment, as set forth in Exhibit A to the Resolution.

g. The Resolution and Exhibit A also provide that, if Mr. Via is not selected as the permanent President and CEO, he may return to his former position, in accordance with the applicable terms set forth on Exhibit A.

ACTION

Board approval of the appointment of Troy R. Via as Interim President and Chief Executive Officer, effective December 27, 2026, and of the compensation set forth on Exhibit A.

RECOMMENDED:	APPROVED FOR BOARD CONSIDERATION:
_____	_____
Mary Spurgeon Chair – Governance Committee	Matt Core Chair – Board of Directors

Attachments: Resolution
Exhibit A

EXHIBIT A

OMAHA PUBLIC POWER DISTRICT
COMPENSATION FOR INTERIM PRESIDENT AND CEO

APPROVAL DATE: November 19, 2026

Officer	Total Annualized Compensation	% of CEO Midpoint	Effective Date
Troy R. Via Interim President and CEO	$797,734	80%	December 27, 2026

Terms of Interim Assignment

1. **Interim Compensation.** During his service as Interim President and Chief Executive Officer, Mr. Via shall receive annualized compensation equal to eighty percent (80%) of the midpoint of the salary range established for the President and Chief Executive Officer position, in the annualized amount of $797,734. Such compensation shall be paid through the District's regular payroll practices and prorated for any partial pay period. This compensation is temporary and applies solely to the interim assignment. It shall not constitute a permanent adjustment to Mr. Via's base salary and shall cease upon conclusion of the interim appointment.
2. **Benefits.** During the interim appointment, Mr. Via shall remain eligible for employee benefits in accordance with District policies and the terms of applicable benefit plans.
3. **Existing Employment Arrangements.** Except as expressly modified by the Board in connection with this interim appointment, Mr. Via's existing employment relationship with the District remains in effect.
4. **Conclusion of Interim Appointment.** If Mr. Via is not selected as permanent President and Chief Executive Officer and his interim appointment concludes, he may return to his former position as Chief Operating Officer. Upon return, his compensation and benefits shall be governed by his existing employment arrangements and applicable District policies.
5. **No Entitlement to Permanent Appointment.** The interim appointment and any opportunity to return to the Chief Operating Officer position do not create any entitlement, guarantee or expectation of appointment to the permanent President and Chief Executive Officer position.

Omaha Public Power District
BOARD OF DIRECTORS

Spurgeon/Wheeler

RESOLUTION NO. XXXX

Appointment of Interim President and Chief Executive Officer

WHEREAS, Board Policy GP-3: Board Job Description provides that the Board of Directors is responsible for the hiring and appointment, as well as compensation and benefit approval, of the President and Chief Executive Officer (CEO); and

WHEREAS, CEO L. Javier Fernandez has announced that he will step down from his position effective December 31, 2026; and

WHEREAS, the Governance Committee has recommended Troy R. Via, currently serving as Chief Operating Officer and Vice President Utility Operations, to serve as Interim President and CEO, based on his experience, operational knowledge and familiarity with the District; and

WHEREAS, the Board desires to ensure leadership continuity and the effective management and operation of the District while the Board conducts a separate search and selection process for the permanent President and CEO.

NOW, THEREFORE, BE IT RESOLVED by the Board of Directors of the Omaha Public Power District that Troy R. Via is hereby appointed Interim President and Chief Executive Officer of the District, effective December 27, 2026, with the compensation set forth on the attached Exhibit A; and

BE IT FURTHER RESOLVED that the Interim President and CEO shall have the full authority and responsibilities of the President and CEO as outlined in OPPD's bylaws, policies and position description, subject to the oversight of the Board of Directors; and

BE IT FURTHER RESOLVED that the interim appointment shall remain in effect until further action by the Board of Directors; and

BE IT FURTHER RESOLVED that this interim appointment does not confer any entitlement, guarantee or expectation of appointment to the permanent President and CEO position, and the Board retains its authority and responsibility to conduct a separate search and selection process and appoint the permanent President and CEO; and

BE IT FURTHER RESOLVED that, in the event Mr. Via is not selected as the permanent President and CEO and his interim appointment concludes, he may return to his former position as Chief Operating Officer, in accordance with the applicable terms set forth in Exhibit A; and

BE IT FURTHER RESOLVED that District Management is hereby authorized and directed to take all actions necessary to implement this resolution, consistent with the Board's action and applicable law.

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Omaha Public Power District
BOARD OF DIRECTORS

Board Action

November 17, 2026

ITEM

2027 Board Meeting Schedule - Updated

PURPOSE

Approve updated start times for the 2027 Board of Directors Board meetings.

FACTS

a. Article IV, Section 1 of the Bylaws of the Omaha Public Power District directs that the Board annually shall approve a schedule of regular Board meetings.

b. The Board of Directors approved the 2027 Board of Directors meeting schedule in September of 2026.

c. The start time of all Board of Directors Board meetings in 2027 will be changed to 5:30 p.m. due to scheduling conflicts at the Douglas County Civic Center legislative chamber.

ACTION

Obtain approval from the Board of Directors to update the 2027 Board meeting start times.

RECOMMENDED:

Signed by:
Scott M. Focht
B626AD4292E3483...
Scott M. Focht
Vice President – Corporate Strategy and Governance

APPROVED FOR BOARD CONSIDERATION:

Signed by:
L. Javier Fernandez
AC399FDCE50247E...
L. Javier Fernandez
President and Chief Executive Officer

Attachments:
Exhibit A – 2027 Updated Board Mtg Schedule
Resolution

Exhibit A
Omaha Public Power District
Board of Directors
2027 Regular Board Meeting Schedule - Updated

All Committees Meeting Tuesdays				Board Meeting Thursdays		
Date*	**Location***	**Time***		**Date***	**Location***	**Time***
January 19	BCBS 1919 Aksarben Dr.	10:00 a.m.		January 21	Omaha Douglas Civic Center	5:30 p.m.
February 16	BCBS 1919 Aksarben Dr.	10:00 a.m.		February 18	Omaha Douglas Civic Center	5:30 p.m.
March 16	BCBS 1919 Aksarben Dr.	10:00 a.m.		March 18	Omaha Douglas Civic Center	5:30 p.m.
April 13	BCBS 1919 Aksarben Dr.	10:00 a.m.		April 15	Omaha Douglas Civic Center	5:30 p.m.
May 18	BCBS 1919 Aksarben Dr.	10:00 a.m.		May 20	Omaha Douglas Civic Center	5:30 p.m.
June 15	BCBS 1919 Aksarben Dr.	10:00 a.m.		June 17	Omaha Douglas Civic Center	5:30 p.m.
July – No Meeting						
August 17	BCBS 1919 Aksarben Dr.	10:00 a.m.		August 19	Omaha Douglas Civic Center	5:30 p.m.
Board Governance Workshop – August 26	BCBS 1919 Aksarben Dr.	8:30 a.m.				
September 14	BCBS 1919 Aksarben Dr.	10:00 a.m.		September 16	Omaha Douglas Civic Center	5:30 p.m.
October 19	BCBS 1919 Aksarben Dr.	10:00 a.m.		October 21	Omaha Douglas Civic Center	5:30 p.m.
November 15**	BCBS 1919 Aksarben Dr.	10:00 a.m.		November 18	Omaha Douglas Civic Center	5:30 p.m.
December 14	BCBS 1919 Aksarben Dr.	10:00 a.m.		December 16	Omaha Douglas Civic Center	5:30 p.m.

**Dates, times, and locations are subject to change. All meeting information will be publicly noticed in advance of the meeting. The public may attend in person or remotely via the WebEx audio/video conferencing platform.*

***All Committees will be held Monday, November 15th due to a scheduling conflict on the 16th.*

Spurgeon/Focht

RESOLUTION NO. 6xxx

WHEREAS, Article IV, Section 1 of the Bylaws of the Omaha Public Power District directs that the Board annually shall approve a schedule of regular Board meetings;

WHEREAS, the Board of Directors approved the 2027 Board meeting schedule in September 2026;

WHEREAS, there are scheduling conflicts with the Douglas County Civic Center legislative chamber on the Board of Directors approved third Thursday of every month Board meeting dates;

NOW, THEREFORE, BE IT RESOLVED by the Board of Directors of the Omaha Public Power District that the updated Board meeting schedule for 2027, as outlined on Exhibit A attached hereto, is hereby approved.

DRAFT

Omaha Public Power District
BOARD OF DIRECTORS

Agenda

OPPD BOARD OF DIRECTORS
REGULAR BOARD MEETING
Thursday, November 19 at 5:00 P.M.

Conducted in person at the Omaha Douglas Civic Center, 1819 Farnam Street, 2nd Floor Legislative Chamber, Omaha, NE 68183
Public may attend in person at the Omaha Douglas Civic Center or remotely by going to www.oppd.com/BoardAgenda to access the Webex meeting link and view materials.

Preliminary Items

1. Chair Opening Statement
2. Safety Briefing
3. Guidelines for Participation
4. Roll Call
5. Announcement regarding public notice of meeting

Board Consent Action Items

6. Approval of the September 2026 Financial Report, October 2026 Meeting Minutes, and November 19, 2026 Agenda
7. Update to 2027 Board Meeting Schedule – Resolution No. 6xxx
8. Retirement Plan Investment Policy Update – Resolution No. 6xxx
9. Acquisition of Land Rights for Utility Operations Infrastructure Projects - Cass to Nebraska City Transmission Project – Resolution No. 6xxx
10. Acquisition of Land Rights for Utility Operations Infrastructure Projects - Bellevue Reliability Project: Olde Towne Transmission – Resolution No. 6xxx
11. Hastings/Grand Island Utilities Inter-local Agreement – Resolution No. 6xxx
12. RFP 6263 - Nebraska City 1 House Service Transformer – Resolution No. 6xxx
13. SD-11: Economic Development Monitoring Report – Resolution No. 6xxx
14. Appointment of Interim CEO – Resolution No. 6xxx

Board Discussion Action Items

TBD

Other Items

15. President's Report
16. Opportunity for comment on other items of District business
17. Adjournment

Please use the link below to find all committee and board agendas, materials and schedules. Board governance policies and contact information for the board and senior management team also can be found at www.oppd.com/BoardMeetings.