Agenda
Utility Advisory Committee Meeting
Tuesday, July 11, 2023
Richland City Hall ~ Council Chambers
625 Swift Boulevard

Committee Members: Chair Lo Presti, Vice-Chair Larkin and Members Miller, Porter, and Staven

Council Liaisons: Council Liaison: VanDyke
Council Liaison Alternate: Jones
Staff Liaison: Whitney

Regular Meeting - 3:00 p.m.

Call to Order/Attendance:

Approval of Agenda: (Approved by Motion)

Approval of Minutes: (Approved by Motion)

1. Approval of May 9, 2023 Meeting Minutes
   - Karla Palomarez, Administrative Assistant II

Public Comments:

Items of Business:

2. Status- Each City Utility (10 Minutes Each)
   -
3. Results of 2023 Electric Revenue Bond Issue
   - Clint Whitney, Energy Services Director
4. Net Metering Study with Washington Public Utility District Association
   - Clint Whitney, Energy Services Director
5. PURPA 111d Requirements to Consider Additional Demand Response (DR) and Electric Vehicle (EV) Charging Programs
   - Clint Whitney, Energy Services Director

Unfinished Business:

Other Informational Items:

6. Capital Work Plan Update - May 2023
   - Clint Whitney, Energy Services Director
7. Draft Capital Improvement Projects for 2024-2030
   - Clint Whitney, Energy Services Director
8. Resource Adequacy - 3rd Annual Webinar by WA Utilities and Transportation Commission and WA Department of Commerce

- Clint Whitney, Energy Services Director

9. Advanced Metering Infrastructure (AMI) Status
   - Clint Whitney, Energy Services Director

10. Forward Agenda Items
    - Clint Whitney, Energy Services Director

Adjournment

Richland City Hall is ADA accessible. Any individual who has difficulty attending the meeting in-person may request to provide comments remotely. (Ch. 42.30 RCW) Requests for sign interpreters, audio equipment, and/or other special services must be received 48 hours prior to the meeting by calling the City Clerk's Office at 509-942-7389.

UTILITY ADVISORY COMMITTEE AGENDA ITEM COVERSHEET

Meeting Date: 7/11/2023 Agenda Category: Approval of Minutes

Prepared By: Karla Palomarez, Administrative Assistant II

Subject:
Approval of May 9, 2023 Meeting Minutes

Department:
Energy Services

Recommended Motion:
Approve the minutes of the UAC meeting held on May 9, 2023.

Summary:

Fiscal Impact:

Attachments:
1. Draft UAC Meeting Minutes 5.9.23

MINUTES
UTILITY ADVISORY COMMITTEE REGULAR MEETING
Tuesday, May 9, 2023
Richland City Hall - Council Chambers

Utility Advisory Committee Regular Meeting – 3:00 P.M.
Chair Lo Presti called the meeting to order at 3:00 P.M.

Attendance: Chair Lo Presti, Vice Chair Larkin, and Committee Members Porter, Staven and Miller were present. Also present were Staff Liaison and Energy Services Director Whitney, Council Liaison VanDyke, Fire & Emergency Services Director Huntington, Fire Battalion Chief VanBeek, Deputy Fire Chief Aust, Business Services Manager Edgemon, Fire & Emergency Services Analyst Auchmoody and Administrative Assistant Palomarez.

Approval of Agenda

MEMBER PORTER MOVED AND MEMBER STAVEN SECONDED THE MOTION TO APPROVE THE AGENDA AS PUBLISHED. THE MOTION CARRIED 5-0.

Approval of Minutes

MEMBER LARKIN MOVED AND MEMBER PORTER SECONDED THE MOTION TO APPROVE THE MARCH 14, 2023 MEETING MINUTES WITH THE REQUESTED AMENDMENTS. THE MOTION CARRIED 5-0.

Public Comments

None.

Items of Business

1. Status- Each City Utility

Energy Services Director Whitney provided a status on AMI electric and water. He stated that electric is over 90% installed and water is 50% installed with approximately 10,000 out of 20,000 completed. Itron and Keystone have resumed water and electric meter installations. He reported that staff is working on a customer portal where usage and outage maps would be accessible by customers. Mr. Whitney responded to questions from members.

2. 2024 Medical Utility Rate Setting

Fire Battalion Chief VanBeek discussed the 2024 Medical Utility Rate Setting recommendation. He reported rates have been held at $10 per month for the last two years which is longer than originally forecasted. He stated that Council and the Utility Advisory Committee (UAC) members have indicated small incremental increases would be preferred over steep, infrequent adjustments. Mr. VanBeek said there is also the potential to lose GEMT funding with many unknown factors, and it is projected that a possible 25% decrease ($400,000) in these funds may exist, and Station 77 has been added to the City's Capital Improvements Projects. He stated the utility is seeking an endorsement on the 2024 monthly household Ambulance Utility Fee increase which will raise rates from $10 to $11.47 per month effective January 1, 2024, and the UAC unanimously agreed to this recommendation previously. Mr. VanBeek responded to questions from members.

3. BPA Provider of Choice Discussions for 2028 Contracts

Energy Services Director Whitney communicated that there are 134 public power entities supplied by Bonneville Power Administration (BPA). Public Power Council (PPC) and Northwest Requirements Utilities (NRU) continue advocating for the City and other public power entities during discussions for post 2028 wholesale power and transmission contracts. There is not always a consensus within the public power entities. Mr. Whitney provided a proposed BPA timeline for the 2028 contracts and informed members that the 2028 wholesale power and transmission contract with BPA will look similar to the existing 2008 contract with a Tier 1 and Tier 2 basis of a tiered rate methodology (TRM). Mr. Whitney responded to questions from members.

4. Reliability Statistics-

Energy Services Director Whitney presented an update on electric reliability. The data shows areas of potential renewal and replacement capital projects for 2024. The presentation provided information on data from 2020-2023 regarding outages by category, group and year. Mr. Whitney answered questions from members.

5. Energy Services (RES) Capital Work Plan Update

Energy Services Director Whitney presented financial data from the RES Capital Work Plan (CWP). He followed up by identifying significant areas of capital work, which included Advanced Metering Infrastructure (AMI), System Improvements, Renewals & Replacements, Substation Improvements, and Line Extensions. He provided a presentation summarizing the 2023 CWP through April. Mr. Whitney concluded by responded to questions.

6. Energy Services Supply Chain Status

Energy Services Director Whitney stated that electrical distribution infrastructure continues to have supply chain delays; in particular, electrical transformers have the greatest impact on inventory deliveries. Mr. Whitney reported that distribution transformers on order have an estimated availability in 2024 and into 2025. He concluded that RES' four substation transformers will be installed at City View Bank 2 (2023), Stevens Bank 1 replacement (2024), Thayer Bank 1 replacement (2025), and Sandhill Bank 3 (2026). Mr. Whitney responded to questions from members.

Unfinished Business

None.

Other Informational Items

The following items from the forward-planning agenda were provided to Members for review and discussion at future meetings:

- Capital Improvement Plan (July)
- Resource Adequacy and Regional Transmission Organization (RTO) (September)
- Electric Services Rate Recommendation (November)
- Election of UAC Chair and Vice Chair (January)
- Electric Cost of Service Analysis (COSA) (January)

Adjournment

Chair LoPresti adjourned the meeting at 5:00 p.m.

APPROVED: ATTESTED:

__________________________________ __________________________________

Chair LoPresti, Utility Advisory Committee Karla Palomarez, Administrative Assistant

DATE APPROVED:

DATE PUBLISHED:

UTILITY ADVISORY COMMITTEE AGENDA ITEM COVERSHEET

Meeting Date: 7/11/2023 | Agenda Category: Items of Business

Prepared By:

Subject:
Status- Each City Utility (10 Minutes Each)

Department:
Energy Services

Recommended Motion:
This item is informational only.

Summary:
A representative from each of the City's utilities will provide a status update.

Fiscal Impact:

Attachments:

UTILITY ADVISORY COMMITTEE AGENDA ITEM COVERSHEET

Meeting Date: 7/11/2023 Agenda Category: Items of Business

Prepared By: Clint Whitney, Energy Services Director

Subject:
Results of 2023 Electric Revenue Bond Issue

Department:
Energy Services

Recommended Motion:
No action needed.

Summary:
On May 9, 2023, the City received comments from S&P Global Ratings with a bond rating recommendation of "A" for new issuance of electric revenue bonds, "A" rating for existing outstanding electric revenue bonds with a stable outlook for the utility.

S&P Global Ratings comments are attached and summarized as:

- Fixed Cost Coverage (FCC) of 1.49x in 2022 compared to 1.58x in 2021 and an improvement from 1.35 in 2020.
- An increase in liquidity of $13.3M in 2022, representing 78 days of unrestricted cash for operating expenses.
- "Limited exposure to operational risks as an offtaker of Bonneville Power Authority (BPA)".
- "System rates were 91% of the state average in 2021".
- "Robust service area economy".
- "Sound risk management and operational planning around environmental compliance, system reliability, and emergency preparedness, which helps enhance operational stability".
- "High debt burden profile marked by a debt-to-capitalization ratio of 51% as of fiscal 2022".

On May 24, 2023, the City issued $19,415,00 of new electric revenue bonds with a $1,837,801.95 premium received. This resulted in $8,000,000 of new revenue bonds available to support capital work plans and $13,536,128.47 being used to refund higher cost 2013 bonds. City staff anticipate using the new revenue bonds over the 2023-2025 capital work period. Attached is the detailed official statement used for the revenue bond issuance.

Fiscal Impact:
There is no fiscal impact.

Attachments:
1. Richland-Electric Rev 2023-Final Official Statement 4882-8301-6804_3
2. Draft S&P Global Report for Issuer_Richland WA 05092023

OFFICIAL STATEMENT

NEW ISSUE – BOOK-ENTRY ONLY | **S&P Ratings:**
Underlying: A
Insured: AA
See "BOND INSURANCE" and "OTHER BOND INFORMATION—Ratings on the Bonds" herein

In the opinion of Stradling Yocca Carlson & Rauth, a Professional Corporation, Seattle, Washington ("Bond Counsel"), under existing statutes, regulations, rulings and judicial decisions, and assuming the accuracy of certain representations and compliance with certain covenants and requirements described herein, interest on the Bonds is excluded from gross income for federal income tax purposes and is not an item of tax preference for purposes of calculating the federal alternative minimum tax imposed on individuals with respect to tax consequences relating to the Bonds, including with respect to the alternative minimum tax imposed on certain large corporations for tax years beginning after December 31, 2022. See "LEGAL AND TAX INFORMATION—Tax Matters"

City of Richland, Washington
$19,415,000
Electric Utility Revenue Improvement and Refunding Bonds, 2023

Dated: As of the Delivery Date | **Due:** November 1, as shown on page ii

The City of Richland, Washington (the "City") Electric Utility Revenue Improvement and Refunding Bonds, 2023 (the "Bonds") will be issued in fully registered form only and, when issued, will be registered in the name of Cede & Co., as nominee of The Depository Trust Company, New York, New York ("DTC"). DTC will act as securities depository for the Bonds (the "Securities Depository"). Individual purchases of interests in the Bonds will be made in Book-Entry Form (as defined below) only, in the principal amount of $5,000 or any integral multiple thereof within a maturity. Purchasers of such interests ("Beneficial Owners") will not receive certificates representing their interests in the Bonds. Principal and interest are payable directly to DTC by the fiscal agent of the state of Washington (the "State"), currently, U.S. Bank Trust Company, National Association, as transfer agent, authenticating agent, paying agent and registrar (the "Bond Registrar").

Interest on the Bonds is payable semiannually on each May 1 and November 1, commencing November 1, 2023, to the maturity or earlier redemption of the Bonds. The Bonds will mature on the dates and in the amounts and bear interest at the rates set forth on page ii. For so long as the Bonds are held in Book-Entry Form, the principal and interest on the Bonds will be paid by the Bond Registrar to the Securities Depository, which in turn is obligated to remit such payments to its broker-dealer participants for subsequent disbursement to the Beneficial Owners. See "DESCRIPTION OF THE BONDS—Registration and Payment" and APPENDIX D—BOOK-ENTRY TRANSFER SYSTEM.

The scheduled payment of principal of and interest on the Bonds when due will be guaranteed under a municipal bond insurance policy to be issued concurrently with the delivery of the Bonds by **BUILD AMERICA MUTUAL ASSURANCE COMPANY.**

Proceeds of the Bonds will be used: (i) to carry out the plan of additions and betterments to and extension of the Electric Utility (defined below); (ii) to make a deposit to satisfy the debt service reserve requirement for the Bonds, if necessary; (iii) to refund a portion of the City's outstanding Electric Revenue Improvement and Refunding Bonds, 2013B; and (iv) to pay the costs of issuance of the Bonds and the administrative costs of the refunding. See "USE OF BOND PROCEEDS—Uses of Bond Proceeds."

The Bonds are subject to optional redemption prior to their stated dates of maturity. Depending on market conditions on the day of pricing, some of the Bonds may be sold as Term Bonds, subject to mandatory redemption as described herein. See "DESCRIPTION OF THE BONDS—Redemption Provisions."

The Bonds are special limited obligations of the City payable from and secured solely by the Net Revenue of the Electric Utility and by money in the Principal and Interest Account of the Bond Fund. The Bonds are designated as Common Reserve Bonds and are further secured by money in the Common Reserve Subaccounts. See "SECURITY AND SOURCES OF PAYMENT—The Bond Fund." The Bonds are issued on parity of lien with the Outstanding Parity Bonds and any Future Parity Bonds (together with the Bonds, the "Parity Bonds"). The pledge of Net Revenue in respect of the Parity Bonds constitutes a lien and charge upon the Net Revenue prior and superior to any other charges whatsoever. **The Bonds are not general obligations of the City, and neither the full faith and credit nor the taxing power of the City, the State or any political subdivision thereof is pledged for the payment of the principal of or interest on the Bonds. No revenues of the City derived from any source other than the Net Revenue are pledged to the payment of the Bonds.** See "SECURITY AND SOURCES OF PAYMENT."

The City has NOT designated the Bonds as "qualified tax-exempt obligations" for banks, thrift institutions and other financial institutions under section 265(b)(3) of the Code. See "LEGAL AND TAX INFORMATION—Tax Matters."

This cover page contains certain information for quick reference only. It is not a summary of this issue. Investors must read the entire Official Statement to obtain information essential to making an informed investment decision.

The Bonds are offered when, as, and if executed and delivered, and are subject to receipt of the approving legal opinion of Stradling Yocca Carlson & Rauth, a Professional Corporation, Seattle, Washington, Bond Counsel to the City, and certain other conditions. Bond Counsel will also act as Disclosure Counsel to the City. It is expected that the Bonds will be available for delivery through the facilities of DTC or to the Bond Registrar on behalf of DTC by Fast Automated Securities Transfer, on or about June 6, 2023 (the "Delivery Date").

Dated: May 24, 2023

The information within this Official Statement has been compiled from sources considered reliable and, while not guaranteed as to accuracy, is believed to be correct as of its date. The City makes no representation regarding the accuracy or completeness of the information in APPENDIX D—BOOK-ENTRY TRANSFER SYSTEM, which has been obtained from DTC's website, or regarding the financial advisor. The information and expressions of opinions herein are subject to change without notice, and neither the delivery of this Official Statement nor any sale made hereunder will, under any circumstances, create any implication that there has been no change in the information set forth herein since the date hereof.

Information appearing on websites referenced in this Official Statement, including the websites of the City and City departments, is not incorporated into this Official Statement and cannot be relied upon to be accurate as of the date of this Official Statement. Investors should not rely on any such website in making investment decisions regarding the Bonds.

No dealer, broker, sales representative, or other person has been authorized by the City to give any information or to make any representations other than as contained in this Official Statement in connection with the offering made hereby and, if given or made, such information or representations must not be relied upon as having been authorized by the City. This Official Statement does not constitute an offer to sell or the solicitation of an offer to buy, nor shall there be any sale of the Bonds by any person, in any jurisdiction in which it is unlawful for such persons to make such offer, solicitation or sale.

The Bonds have not been registered under the Securities Act of 1933, as amended, and the Bond Ordinance has not been qualified under the Trust Indenture Act of 1939, as amended, in reliance upon exemptions contained in such acts. The registration or qualification of the Bonds in accordance with applicable provisions of securities laws of the states in which the Bonds have been registered or qualified and the exemption from registration or qualification in other states cannot be regarded as a recommendation thereof. Neither these states nor any of their agencies have passed upon the merits of the Bonds or the accuracy or completeness of this Official Statement. Any representation to the contrary may be a criminal offense.

The presentation of certain information, including tables of receipts from revenues, is intended to show recent historical information and is not intended to indicate future or continuing trends in the financial position or other affairs of the City. No representation is made that past experience, as it might be shown by such financial and other information, will necessarily continue to be repeated in the future. Information relating to statutory and constitutional limitations is based on existing statutes and constitutional provisions. Changes in state law could alter these provisions.

The information set forth in the audited financial statements that are included in Appendix C speaks only as of the date of those statements and is subject to revision or restatement in accordance with applicable accounting principles and procedures. The City specifically disclaims any obligation to update this information except as set forth in the Continuing Disclosure Agreement. See "CONTINUING DISCLOSURE."

Certain statements contained in this Official Statement reflect not historical facts but instead contain forecasts and "forward-looking statements." No assurance can be given that the future results discussed herein will be achieved, and actual results may differ materially from the forecasts described herein. In this respect, the words "estimate," "project," "anticipate," "expect," "intend," "believe" and similar expressions are intended to identify forward-looking statements. The achievement of certain results or other expectations contained in forward-looking statements involves known and unknown risks, uncertainties and other factors that may cause actual results, performance or achievements described to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. All estimates, projections, forecasts, assumptions and other forward-looking statements are expressly qualified in their entirety by the cautionary statements set forth in this Official Statement. These forward-looking statements speak only as of the date they were prepared. The City does not plan to issue any updates or revisions to those forward-looking statements if or when their expectations or events, conditions or circumstances on which such statements are based occur.

The website of the City or any City department or agency is not part of this Official Statement, and investors should not rely on information presented on the City's website, any social media account, or any other internet presence referenced herein, in determining whether to purchase the Bonds. Information appearing on any such website, social media account, or any other internet presence is not incorporated by reference in this Official Statement.

The CUSIP data in this Official Statement are provided by the CUSIP Global Services, managed on behalf of the American Bankers Association by S&P Global Market Intelligence. The CUSIP numbers are not intended to create a database and do not serve in any way as a substitute for CUSIP Global Services. CUSIP numbers have been assigned by an independent company not affiliated with the City and are provided solely for convenience and reference. The CUSIP numbers for a specific maturity are subject to change after the issuance of the Bonds. The City takes no responsibility for the accuracy of the CUSIP numbers.

The order and placement of materials in this Official Statement, including the Appendices, are not to be deemed to be a determination of relevance, materiality or importance, and this Official Statement, including the Appendices, must be considered in its entirety. The offering of the Bonds is made only by means of this entire Official Statement.

Build America Mutual Assurance Company ("BAM") makes no representation regarding the Bonds or the advisability of investing in the Bonds. In addition, BAM has not independently verified, makes no representation regarding, and does not accept any responsibility for the accuracy or completeness of this Official Statement or any information or disclosure contained herein, or omitted herefrom, other than with respect to the accuracy of the information regarding BAM, supplied by BAM and presented under the heading "Bond Insurance" and "Exhibit E- Specimen Municipal Bond Insurance Policy".

$19,415,000
City of Richland, Washington
Electric Utility Revenue Improvement and Refunding Bonds, 2023

Maturity Date (November 1)	Principal Amount	Interest Rate	Yield	Price	CUSIP No.
2024	$ 770,000	5.000%	3.520%	102.005	764267 BD1
2025	805,000	5.000	3.390	103.681	764267 BE9
2026	845,000	5.000	3.250	105.591	764267 BF6
2027	885,000	5.000	3.160	107.504	764267 BG4
2028	940,000	5.000	3.120	109.277	764267 BH2
2029	985,000	5.000	3.100	110.954	764267 BJ8
2030	1,025,000	5.000	3.050	112.831	764267 BK5
2031	1,080,000	5.000	3.050	114.355	764267 BL3
2032	1,135,000	5.000	3.080	115.568	764267 BM1
2033	1,190,000	5.000	3.160(1)	115.538	764267 BN9
2034	515,000	5.000	3.250(1)	114.713	764267 BP4
2035	545,000	5.000	3.400(1)	113.354	764267 BQ2
2036	565,000	5.000	3.560(1)	111.925	764267 BR0
2037	595,000	5.000	3.700(1)	110.693	764267 BS8
2038	625,000	5.000	3.810(1)	109.736	764267 BT6
2039	655,000	5.000	3.860(1)	109.304	764267 BU3
2040	685,000	5.000	3.910(1)	108.875	764267 BV1

$1,475,000 5.000% Term Bonds due November 1, 2042, Yield 4.000%(1), Price 108.106, CUSIP No. 764267 BX7

$1,245,000 5.000% Term Bonds due November 1, 2046, Yield 4.130%(1), Price 107.008, CUSIP No. 764267 CB4

$1,510,000 5.000% Term Bonds due November 1, 2050, Yield 4.240%(1), Price 106.089, CUSIP No. 764267 CF5

$1,340,000 5.000% Term Bonds due November 1, 2053, Yield 4.300%(1), Price 105.592, CUSIP No. 764267 CJ7

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(1) Yield calculated to the May 1, 2033 par call date.

CITY OF RICHLAND, WASHINGTON
625 Swift Boulevard
Richland, Washington 99352
(509) 942-7390
www.ci.richland.wa.us

ELECTED OFFICIALS

CITY COUNCIL

Terry Christensen	Mayor
Teresa Richardson	Mayor Pro Tem
Jhoanna Jones	Council Member
Sandra Kent	Council Member
Ryan Lukson	Council Member
Shayne VanDyke	Council Member
Ryan Whitten	Council Member

CERTAIN APPOINTED OFFICIALS

Jon Amundson	City Manager
Drew Florence	Assistant City Manager
Heather Kintzley	City Attorney
Brandon Allen	Finance Director
Brandon Suchy	Finance Manager
Clint Whitney	Energy Services Director

BOND AND DISCLOSURE COUNSEL

Stradling Yocca Carlson & Rauth,
a Professional Corporation
Seattle, Washington

FINANCIAL ADVISOR

PFM Financial Advisors LLC
Seattle, Washington

BOND REGISTRAR

Washington State Fiscal Agent
(Currently U.S. Bank Trust Company, National Association)

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APPENDICES

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OFFICIAL STATEMENT

CITY OF RICHLAND, WASHINGTON

$19,415,000
Electric Utility Revenue Improvement and Refunding Bonds, 2023

INTRODUCTION

The City of Richland (the "City"), a duly organized municipal corporation and a legally existing charter city of the first class under the laws of the state of Washington (the "State"), furnishes this Official Statement in connection with the offering of its Electric Utility Revenue Improvement and Refunding Bonds, 2023 (the "Bonds"). This Official Statement, which includes the cover page, inside cover page, the table of contents and appendices, provides information concerning the City; the municipal electric system of the City as the same may from time to time be added to, bettered, improved and extended (the "Electric Utility"); and the Bonds.

Capitalized terms not otherwise defined herein shall have the meanings assigned to them in the Bond Ordinance (as defined below). See APPENDIX A—THE BOND ORDINANCE—Article 1.

All of the summaries of provisions of the Constitution and laws of the State, of ordinances of the City, and of other documents contained herein are subject to the complete provisions thereof and do not purport to be complete statements of such laws or documents, copies of which may be obtained from the City upon request. A full review should be made of the entire Official Statement. The offering of the Bonds to prospective investors is made only by means of the entire Official Statement.

Changes Since the Date of the Preliminary Official Statement

In reviewing this final Official Statement, the City discovered two inadvertent errors that have been corrected. In Table 9, the cell showing Miscellaneous Non-Operating Revenues (Expenses) for 2022 inadvertently duplicated the information from the cell below. This typographical error has been corrected and no other cells are affected. In addition, under the heading "THE CITY," the City Manager's biography has been updated to remove the "Interim" from his title and reflect his formal appointment as City Manager.

DESCRIPTION OF THE BONDS

General

The Bonds will be dated as of their initial date of delivery (the "Delivery Date") and will bear interest from their Delivery Date or the most recent date to which interest has been paid or provided for. Interest on the Bonds will be payable semiannually on each May 1 and November 1, commencing November 1, 2023. The Bonds will bear interest at the rates and will mature on the dates and in the amounts set forth on the inside cover of this Official Statement. Interest will be calculated on the basis of a 360-day year consisting of twelve 30-day months.

Authorization

The Bonds are issued pursuant to the provisions of the Constitution of the State, the Charter of the City of Richland, chapters 35.41, 35.92, and 39.46 of the Revised Code of Washington ("RCW") and other applicable laws of the State, and Ordinance No. 2023-06 passed by the City Council (the "City Council") at a regular meeting on April 18, 2023 providing for the issuance and sale of the Bonds (the "Bond Ordinance").

Registration and Payment

Book-Entry System. The Bonds will be issued as fully registered bonds and, when issued, will be registered in the name of Cede & Co. as nominee for The Depository Trust Company ("DTC"). DTC will act as the initial Securities Depository for the Bonds. Individual purchases and sales of the Bonds will be made in Book-Entry Form only in minimum denominations of $5,000 or integral multiples thereof within a maturity ("Authorized Denominations"). Purchasers ("Beneficial Owners") will not receive certificates representing their interests in the Bonds. So long as Cede & Co. is the Registered Owner of the Bonds, as nominee of DTC, references herein to the Registered Owners will mean Cede & Co. or its successor and will not mean the Beneficial Owners of the Bonds. For information about

DTC and its book-entry system, see APPENDIX D—BOOK-ENTRY TRANSFER SYSTEM. The City makes no representation as to the accuracy or completeness of the information in Appendix D provided by DTC. Purchasers of the Bonds should confirm this information with DTC or its broker-dealer participants.

Bond Registrar. The principal of and interest on the Bonds will be payable by the fiscal agent of the State (the "Bond Registrar"), currently U.S. Bank Trust Company, National Association. So long as Cede & Co. is the Registered Owner of the Bonds, principal of and interest on the Bonds will be payable by wire transfer by the Bond Registrar to DTC, which, in turn, is obligated to remit such principal and interest to its participants for subsequent disbursement to the Beneficial Owners of the Bonds, as further described in APPENDIX D—BOOK-ENTRY TRANSFER SYSTEM.

Transfer and Exchange; Record Date. The Bond Registrar is not obligated to exchange any Bond or transfer registered ownership during the period between the applicable Record Date and the next interest payment or redemption date. Record Date means, in the case of each interest payment date, the Bond Registrar's close of business on the 15th day of the month immediately preceding such interest payment date, and, with respect to redemption of a Bond prior to its maturity, the Bond Registrar's close of business on the date on which the Bond Registrar sends the notice of redemption in accordance with the Bond Ordinance. Registered ownership of any Bond registered in the name of the Securities Depository may not be transferred except (i) to any successor Securities Depository; (ii) to any substitute Securities Depository appointed by the City; or (iii) to any person if the Bond is no longer to be held in Book-Entry Form.

Termination of Book-Entry System. If the Bonds are no longer held in Book-Entry Form, the City will execute, authenticate and deliver, at no cost to the Beneficial Owners, Bonds in fully registered form, in Authorized Denominations. The principal of the Bonds will then be payable upon due presentment and surrender to the Bond Registrar, and interest on the Bonds will then be payable by electronic transfer on the interest payment date, or by check or draft of the Bond Registrar mailed on the interest payment date, to the Registered Owners, at the address appearing upon the registration books on the Record Date. The City is not required to make electronic transfers except pursuant to a request by a Registered Owner in writing received on or prior to the Record Date and at the sole expense of the Registered Owner.

Redemption Provisions

Optional Redemption. The Bonds maturing on November 1 in the years 2024 through 2032, inclusive, are not subject to redemption prior to their stated maturity. The Bonds maturing on or after November 1, 2033, are subject to optional redemption, as a whole or in part (and if in part, with maturities to be selected by the City), on any date on or after May 1, 2033, at a price equal to 100% of the principal amount to be redeemed plus accrued interest, if any, to the date fixed for redemption.

Mandatory Redemption. The Bonds maturing in the years 2042, 2046, 2050, and 2053 are Term Bonds and, if not optionally redeemed or purchased in accordance with the Bond Ordinance, will be called for redemption at a price equal to 100 percent of the principal amount to be redeemed, plus accrued interest, if any, to the date fixed for redemption, on November 1 in years and amounts as follows:

[Remainder of page blank.]

Term Bonds

Term Bonds Maturing 2042	
Year	**Principal Amount**
2041	$715,000
2042(1)	760,000

Term Bonds Maturing 2046	
Year	**Principal Amount**
2043	$290,000
2044	300,000
2045	320,000
2046(1)	335,000

Term Bonds Maturing 2050	
Year	**Principal Amount**
2047	$350,000
2048	370,000
2049	385,000
2050(1)	405,000

Term Bonds Maturing 2053	
Year	**Principal Amount**
2051	$425,000
2052	445,000
2053(1)	470,000

(1) Final maturity.

If a Term Bond is redeemed pursuant to the optional redemption provisions, defeased or purchased by the City and surrendered for cancellation, the principal amount of the Term Bond so redeemed, defeased or purchased (irrespective of its actual purchase price) will be credited against one or more scheduled mandatory redemption installments for that Term Bond determined by the City in the manner described below under "—*Selection of Bonds for Redemption*."

Selection of Bonds for Redemption. If fewer than all of the outstanding Bonds are to be redeemed at the option of the City, the City will select the maturities to be redeemed. If less than all of the principal amount of a maturity is to be redeemed, the Securities Depository will select Bonds held in Book-Entry Form to be redeemed in accordance with the operational procedures of DTC referred to in the Letter of Representations and, if the Bonds are not held in Book-Entry Form, the Bond Registrar will select the Bonds to be redeemed at random in such manner as the Bond Registrar determines. All or a portion of the principal amount of any Bond that is to be redeemed may be redeemed in any Authorized Denomination. If less than all of the outstanding principal amount of any Bond is redeemed, upon surrender of that Bond to the Bond Registrar, there will be issued to the Registered Owner, without charge, a new Bond (or Bonds, at the option of the Registered Owner) of the same maturity and interest rate in any Authorized Denomination in the aggregate principal amount to remain outstanding.

Notice of Redemption. While the Bonds are held in Book-Entry Form, any notice of redemption will be given to the Securities Depository at the time and in the manner required by the Letter of Representations, and the Bond Registrar will not be required to give any other notice of redemption. If the Bonds cease to be in Book-Entry Form, unless waived by any Registered Owner of the Bond to be redeemed, official notice of any redemption of Bonds will be given by the Bond Registrar on behalf of the City by mailing a copy of an official redemption notice by first-class mail, postage prepaid, not less than 20 nor more than 60 days prior to the date fixed for redemption, to the Registered Owners of the Bonds to be redeemed at the addresses appearing on the Bond Register at the time the Bond Registrar prepares the notice.

Effect of Call for Redemption. Interest on each Bond called for redemption will cease to accrue on the date fixed for redemption unless money sufficient to effect such redemption is not on deposit in the Bond Fund or delivered to the Bond Registrar for purposes of redeeming Bonds, or in a trust account established to refund or defease the Bonds.

Rescission of Optional Redemption Notice. In the case of an optional redemption, the notice of redemption may state that the City retains the right to rescind the redemption notice and the redemption by giving a notice of rescission to the affected Registered Owners at any time on or prior to the date fixed for redemption. Any notice of optional redemption that is so rescinded shall be of no effect, and each Bond for which a notice of redemption has been rescinded shall remain outstanding.

Purchase

The City has reserved the right to purchase any or all of the Bonds then available for purchase at any time at any price acceptable to the City plus accrued interest to the date of purchase.

Failure to Pay Bonds

If the principal of any Bond is not paid when properly presented at its maturity or date fixed for redemption, as applicable, the City will be obligated to pay interest on that Bond at the same rate provided in that Bond from and after its maturity or date fixed for redemption until that Bond, both principal and interest, is paid in full or until sufficient money for its payment in full is on deposit in the Bond Fund, or in a trust account established to refund or defease that Bond, and that Bond has been called for payment by giving notice of that call to the Registered Owner.

Defeasance

The City may use money available from any lawful source, including proceeds of the sale of refunding bonds, to carry out a refunding or defeasance plan, which may include (i) paying when due the principal of and interest on any or all of the Bonds (the "defeased Bonds"); (ii) redeeming the defeased Bonds prior to their maturity; and (iii) paying the costs of the refunding or defeasance. If the City sets aside in a special trust fund or escrow account irrevocably pledged to that redemption or defeasance (the "trust account"), money and/or government obligations (see definition below) maturing at a time or times and bearing interest in amounts sufficient to redeem, refund or defease the defeased Bonds in accordance with their terms, then all right and interest of the Owners of the defeased Bonds in the covenants of the Bond Ordinance and, except as provided below, in the Net Revenue of the Electric Utility, funds and accounts obligated to the payment of the defeased Bonds will cease and become void. Thereafter, the Owners of defeased Bonds will have the right to receive payment of the principal of and interest on the defeased Bonds from the trust account and, if funds in the trust account are not available for such payment, will have the residual right to receive payment of principal and interest on the defeased Bonds from the Net Revenue of the Electric Utility without any priority of lien or charge on that revenue or covenants with respect thereto except to be paid therefrom. After the establishing and full funding of such a trust account, the City may then apply money remaining in any fund or account (other than the trust account) established for the payment or redemption of the defeased Bonds to any lawful purpose, subject only to the rights of the owners of any other Parity Bonds then outstanding.

If the refunding or defeasance plan provides that the defeased Bonds or the refunding bonds to be issued be secured by money and/or Government Obligations pending the prior redemption of the defeased Bonds and if such refunding plan also provides that certain money and/or Government Obligations are pledged irrevocably for the prior redemption of the defeased Bonds included in that refunding plan, then only the debt service on the Bonds which are not defeased Bonds and the refunding bonds, the payment of which is not so secured by the refunding plan, will be included in the computation of the Coverage Requirement for the issuance of Future Parity Bonds and the annual computation of coverage for determining compliance with the rate covenants.

The term "Government Obligations" is defined in the Bond Ordinance to have the meaning given in RCW 39.53.010, as it may be amended from time to time. As currently defined in State law the term "Government Obligations" means: (i) direct obligations of, or obligations the principal of and interest on which are unconditionally guaranteed by the United States of America and bank certificates of deposit secured by such obligations; (ii) bonds, debentures, notes, participation certificates, or other obligations issued by the banks for cooperatives, the Federal Intermediate Credit Bank, the Federal Home Loan Bank system, the Export-Import Bank of the United States, federal land banks, or the Federal National Mortgage Association; (iii) public housing bonds and project notes fully secured by contracts with the United States; and (iv) obligations of financial institutions insured by the Federal Deposit Insurance Corporation or the Federal Savings and Loan Insurance Corporation, to the extent insured or to the extent guaranteed as permitted under any other provision of State law.

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USE OF BOND PROCEEDS

Sources and Uses of Funds

The following table shows the sources and uses of the Bond proceeds:

Sources of Funds	Total
Par Amount of Bonds	$ 19,415,000.00
Original Issue Premium	1,837,801.95
City Contribution to Refunding[1]	771,210.83
Total Sources of Funds	**$ 22,024,012.78**
Uses of Funds	
Deposit to Project Fund	$ 8,000,000.00
Refunding of Refunded Bonds	13,536,128.47
Estimated Costs of Issuance [2]	487,884.31
Total Uses of Funds	**$ 22,024,012.78**

(1) Consists of amounts on deposit in the funds and accounts with respect to the Refunded Bonds and a release of excess amounts from the Common Reserve Subaccount within the Reserve Account which, following the issuance of the Bonds and the defeasance of the Refunded Bonds, will no longer be necessary to maintain the Reserve Requirement.

(2) Costs of issuance include legal fees, financial advisor's fees, underwriting fee, rating agency fees, and other costs incurred in connection with the issuance of the Bonds and carrying out the refunding.

Uses of Bond Proceeds and Plan of Refunding

Proceeds of the Bonds will be used: (i) to carry out the plan of additions and betterments to and extension of the Electric Utility (the "Plan of Additions"); (ii) to make a deposit to satisfy the debt service reserve requirement for the Bonds, if necessary; (iii) to refund the a portion of the City's outstanding Electric Revenue Improvement and Refunding Bonds, 2013B; and (iv) to pay the costs of issuance of the Bonds and the administrative costs of the refunding.

The Plan of Additions includes projects described in Exhibit C to the Bond Ordinance, which comprise a portion of the projects in the Electric Utility's Capital Improvement Plan. See "THE ELECTRIC UTILITY—Capital Improvement Plan" and APPENDIX A—THE BOND ORDINANCE — Exhibit C.

Plan of Refunding. A portion of the proceeds of the Bonds will be used to carry out a current refunding of a portion of the City's Electric Revenue Improvement and Refunding Bonds, 2013B (the "Refunded Bonds"), as identified in the schedule below, to achieve debt service savings. The Refunded Bonds will be called on the date and at the redemption price shown in the table below.

Refunded Bonds
Electric Revenue Improvement and Refunding Bonds, 2013B

Maturity Date (Nov. 1)	Par Amount	Coupon	Redemption Date	Redemption Price	CUSIP Number
2028[1]	$3,945,000	5.00%	6/06/2023	100%	764265NC4
2033[1]	5,030,000	5.00	6/06/2023	100%	764265NH3
2042[1]	4,500,000	4.00	6/06/2023	100%	764265NS9

(1) Term Bond.

SECURITY AND SOURCES OF PAYMENT

Pledge of Net Revenue

The Bonds are issued as Parity Bonds and constitute special limited obligations of the City payable from and secured solely by the Net Revenue of the Electric Utility and by money in the Principal and Interest Account of the Bond Fund. The Bonds are designated as Common Reserve Bonds and are further secured by money in the Common Reserve Subaccount within the Reserve Account. The City may in the future issue Future Parity Bonds designated as Common

Reserve Bonds, or may determine that such Future Parity Bonds are to be secured by a standalone reserve subaccount within the Reserve Account or by no reserve. See the caption "—The Bond Fund—*Reserve Account*" and "—Springing Amendments," below.

The Net Revenue of the Electric Utility has been pledged to make certain payments into the Bond Fund and the Reserve Account. The pledge constitutes a lien and charge upon the Net Revenue of the Electric Utility prior and superior to any other charges whatsoever, and on parity of lien with the Outstanding Parity Bonds and all Future Parity Bonds, without regard to date of issuance or authorization and without preference or priority of right or lien.

The principal of and interest on all Parity Bonds is payable solely from the Bond Fund, which is funded from Net Revenue of the Electric Utility in accordance with the flow of funds set forth in the Bond Ordinance. See "—The Bond Fund" and "—Flow of Funds" below. The definitions of Net Revenue and other related terms are provided in APPENDIX A—THE BOND ORDINANCE—Article 1. The Parity Bonds consist of the Bonds, the Outstanding Parity Bonds and any Future Parity Bonds. The Outstanding Parity Bonds (consisting of the outstanding 2013B Bonds, 2015 Bonds, 2018 Bonds, 2019 Bonds, and 2021 Bonds) are described below under the captions "—Outstanding Parity Bonds." See also "—Future Parity Bonds" below.

The lien on Net Revenue is statutory in nature and no additional act is necessary under State law to perfect such lien against any other party making a claim on Net Revenue. State law provides that the owner of a bond, such as the Parity Bonds, the payment of which is pledged from a special fund has a claim only against that special fund and the amounts of revenue pledged to that special fund. Under State law, any bond owner may bring an action to compel a city to set aside and pay into the special fund (i.e., the Bond Fund) the amount that a city is obligated to set aside and pay therein.

The Bonds are special limited obligations of the City payable solely from the amounts on deposit in certain accounts contained within the Bond Fund, as described above. Neither the full faith and credit nor the taxing power of the City, the State, or any other political subdivision thereof is pledged for the payment of the principal of or interest on the Bonds. No revenues of the City derived from any source other than the Net Revenue are pledged to the payment thereof. The Bonds do not create a lien upon any property owned by or situated within the City or the Electric Utility, except for the lien and charge upon the Net Revenue of the Electric Utility as provided in the Bond Ordinance. The Owners of the Bonds do not have a right to require or compel the City, the State or any political subdivision thereof to levy or use any tax to pay the principal of or interest on the Bonds. ***The Bonds do not constitute general obligations of the City, the State or any political subdivision of the State or a charge upon any general fund or upon any money or other property of the City, the State or any political subdivision of the State not specifically pledged by the Bond Ordinance.***

No Acceleration; Limitations on Remedies; Bankruptcy

Neither the Bonds nor any of the Outstanding Parity Bonds are subject to acceleration upon the occurrence of a default. The City therefore would be liable only for principal and interest payments as they become due. In the event of multiple defaults in payment of principal of or interest on Parity Bonds, the Registered Owner of each Parity Bond would be required to bring a separate action for each such payment not made. This could give rise to a difference in interests between Registered Owners of earlier and later maturing Parity Bonds.

The Bond Ordinance contains springing amendments regarding defaults and remedies that could limit the rights and remedies available to Owners of Parity Bonds in an event of default. These amendments are expected to become effective prior to the final maturity date of the Bonds. See "—Springing Amendments," below and APPENDIX A—THE BOND ORDINANCE—Section 9.02.

The rights and remedies of anyone seeking enforcement of the Bonds are subject to laws of bankruptcy and insolvency and to other laws affecting the rights and remedies of creditors and to the exercise of judicial discretion. See "CERTAIN INVESTMENT CONSIDERATIONS."

The Bond Fund

Debt service on the Bonds is payable solely out of the Electric Revenue Refunding Bond Fund, 1985 (the "Bond Fund"). The Bond Fund is divided into two accounts, the Principal and Interest Account and the Reserve Account. See APPENDIX A—THE BOND ORDINANCE — Section 5.03.

Principal and Interest Account. For so long as the Bonds are outstanding, the City has covenanted in the Bond Ordinance to pay into the Principal and Interest Account, on or before each debt service payment date, an amount sufficient (together with other money then on deposit, including investment earnings retained therein) to pay the principal and interest to become due on the Parity Bonds (including mandatory redemption requirements for Term Bonds) on that debt service payment date.

If there is a deficiency in the Principal and Interest Account to meet payments of either principal of or interest on any Common Reserve Bonds, such deficiency is to be made up from the Common Reserve Subaccounts by the withdrawal of cash therefrom and, after all cash has been depleted, then by draws on any Reserve Security then on deposit in the Common Reserve Subaccounts. See "*—Reserve Account*" below.

Reserve Account. The Bonds and the currently Outstanding Parity Bonds are designated as Common Reserve Bonds, and will remain so for so long as they are outstanding. The Common Reserve Bonds are secured by the amounts currently held in the Common Reserve Account, which serves as a pooled reserve for the Common Reserve Bonds. As used in this Official Statement, the term "Common Reserve Account" refers to the main Reserve Account, plus any Reserve Subaccount that may be established to secure Future Parity Bonds designated as Common Reserve Bonds.

The Bond Ordinance provides that the City has the option to designate Future Parity Bonds as: (i) Common Reserve Bonds; (ii) bonds secured by a standalone Reserve Subaccount apart from the Common Reserve Account; or (iii) bonds not secured by any reserve. However, until the date on which the 2013B Bonds and 2015 Bonds are no longer outstanding (the "Reserve Covenant Date"), all Parity Bonds are deemed Common Reserve Bonds. Any Future Parity Bonds that are not designated as Common Reserve Bonds in the ordinance authorizing their issuance will cease to be secured by the Common Reserve Account on and after that Reserve Covenant Date.

So long as any Common Reserve Bonds (including the Bonds) remain outstanding, the City has covenanted to maintain a balance in the Common Reserve Account equal to the total Reserve Requirement for all Common Reserve Bonds. See APPENDIX A—THE BOND ORDINANCE—Sections 1.01 and 5.03. The "Reserve Requirement" means:

(1) With respect to the Common Reserve Bonds collectively, as of any date of calculation, the lesser of: (i) Maximum Annual Debt Service on all Common Reserve Bonds then Outstanding; or (ii) 125% of Average Annual Debt Service on all Common Reserve Bonds then Outstanding, but at no time shall the Reserve Requirement exceed the Tax Maximum;

(2) With respect to any Future Parity Bonds that are not Common Reserve Bonds, the amount established in the ordinance authorizing their issuance (which may be equal to zero), provided that the Reserve Requirement may not exceed the Tax Maximum; and

(3) With respect to the Bonds, the incremental amount necessary to satisfy the Reserve Requirement for the Common Reserve Bonds, set forth in paragraph (1), above.

All or a portion of the Reserve Requirement may be satisfied by the purchase of a Reserve Security. Reserve Security means a surety bond or policy of insurance, obtained in lieu of cash and policy limit or stated amount equal to part or all of the Reserve Requirement. There is no minimum rating requirement in the Bond Ordinance for the provider of a Reserve Security.

The City may not make withdrawals from the Reserve Account (and the subaccounts therein) of any amounts necessary to satisfy the Reserve Requirement, except to make up a deficiency in the Principal and Interest Account or to make the last scheduled principal payment on then-Outstanding Parity Bonds.

The City must make up any deficiency in the Reserve Account (or any subaccount therein) from the Net Revenue of the Electric Utility first available after making the required payments into the Principal and Interest Account. If the Reserve Account is fully funded to the Reserve Requirement, any money in excess of the Reserve Requirement may be used for any lawful purpose of the Electric Utility.

Upon issuance of the Bonds and the defeasance of the Refunded Bonds, the Reserve Requirement for the Common Reserve Bonds will be $4,652,690, which will be fully funded by funds currently on deposit in the Reserve Account securing the Outstanding Common Reserve Bonds. Upon issuance of the Bonds, no Reserve Security will be used to satisfy any portion of the Reserve Requirement.

Payments into the Bond Fund. The City may, but is not required to, transfer from any legally available funds or accounts of the City any money that is available to meet the required payments to be made into the Bond Fund. If the City fails to make the required payments, the owner of any of the Outstanding Parity Bonds may bring action against the City and compel payment into the Bond Fund from Net Revenue of the Electric Utility.

Investment of Money in the Bond Fund. Money in the Bond Fund may be kept in cash or invested in any investment that is a legal investment for the money of the City at the time of such investment. See generally "THE CITY—

Authorized Investments and City Investment Policy." The City has covenanted that money in the Bond Fund will not be invested at a yield which would cause the Bonds to be arbitrage bonds. See "LEGAL AND TAX INFORMATION—Tax Matters."

Flow of Funds

The City has covenanted in the Bond Ordinance to deposit all Gross Revenue of the Electric Utility into the Electric Fund as collected. The Electric Fund is held separate and apart from all other funds and accounts of the City. Under the Bond Ordinance, money in the Electric Fund may be used only for the following purposes applied in the following order of priority:

i. To pay Operation and Maintenance Expenses;

ii. To meet the debt service requirements with respect to, first, the interest due on and, then, the principal of the Parity Bonds by making the required payments into the Principal and Interest Account;

iii. To make the required payments into the Reserve Account (or the subaccounts therein), including amounts required to repay any draws upon a Reserve Security, if any, and into any other account or subaccount in the Bond Fund; and

iv. For any of the following purposes, without priority: to meet the debt service requirements with respect to any Subordinate Bonds; to redeem and retire any then outstanding electric revenue bonds or to purchase any or all of those bonds and obligations in the open market as provided in the ordinance authorizing their issuance; to make necessary betterments and replacements of or repairs, additions or extensions to the Electric Utility; to make a deposit into the Rate Stabilization Account; or for any other lawful Electric Utility purpose.

Rate Covenant and Coverage Requirement

So long as any Parity Bonds are outstanding, the City has covenanted in the Bond Ordinance to establish, maintain and collect rates and charges for electric services sufficient to meet the Coverage Requirement.

Coverage Requirement. The Coverage Requirement is defined in the Bond Ordinance as an amount of Adjusted Net Revenue, in a given Fiscal Year, at least equal to 1.25 times the Annual Debt Service due in that Fiscal Year on all Parity Bonds then outstanding.

For definitions of "Adjusted Net Revenue," "Net Revenue," "Gross Revenue," and other related terms, see APPENDIX A—THE BOND ORDINANCE—Article 1.

In calculating Adjusted Net Revenue, the City may reduce Annual Debt Service, for purposes of calculating the Coverage Requirement and Reserve Requirement, by the amount scheduled to be received in respect of any Tax Credit Subsidy Bonds issued in the future. See Table 12 "Historical Debt Service Coverage" and the notes thereto. For purposes of determining whether the Coverage Requirement is met, the coverage ratio may also be adjusted for deposits to or withdrawals from the Rate Stabilization Account. Amounts collected in respect of City-imposed utility taxes are included in Gross Revenues and the payment of such taxes is not considered an Operation and Maintenance Expense.

Rate Stabilization Account

The City has established an Electric Utility Rate Stabilization Account within the Electric Fund to permit excess revenues from one Fiscal Year (currently a calendar year) to be temporarily set aside and added to the Net Revenue in a future year for purposes of managing rates and charges, meeting debt service requirements and calculating the Coverage Requirement. See APPENDIX A—THE BOND ORDINANCE—Section 7.03. The City does not have any money currently on deposit in, and has no current plans to make deposits to, the Rate Stabilization Account.

Contract Resource Obligations

The City may at any time enter into one or more contracts or other obligations for the acquisition, from facilities to be constructed or improved, of electric energy supply, transmission or other commodity or service relating to the Electric Utility. The City may determine that such contract or other obligation is a Contract Resource Obligation, and may provide that all payments under such contract will be Operation and Maintenance Expenses so long as: (i) no Event of Default as defined in the Bond Ordinance has occurred and is continuing; and (ii) the City receives a certificate from an Independent Utility Consultant concerning: (a) the reasonableness of payments to be made under the contract; (b) the soundness and feasibility of the project; and (c) the sufficiency of Net Revenue with respect to the Coverage Requirement, taking into account the adjustments permitted under the Parity Bond Test. Payments required to be made under Contract Resource Obligations may not be subject to acceleration. See APPENDIX A—THE BOND ORDINANCE—Section 7.04. The City does not currently have any Contract Resource Obligations.

The City has also reserved the right to enter into agreements for supply or service, which would not be Contract Resource Obligations, and nonetheless to treat such payments as either Operation and Maintenance Expenses or as subordinate to the lien on Net Revenue of the Parity Bonds, as appropriate. See "POWER SUPPLY AND TRANSMISSION—Power Supply—*Bonneville Power Supply Contract*" for a description of the City's supply contracts.

Future Parity Bonds

The City has reserved the right to issue Future Parity Bonds after meeting a Parity Bond Test. See APPENDIX A—THE BOND ORDINANCE—Section 7.05 and Exhibit B. The Parity Bond Test includes:

(a) There may be no deficiency in the Principal and Interest Account, the Reserve Account (and the subaccounts therein) or any other account in the Bond Fund.

(b) The ordinance authorizing any Future Parity Bonds must: (1) determine whether such Future Parity Bonds will be designated as Common Reserve Bonds after the Reserve Covenant Date; (2) set the Reserve Requirement (which may be zero) for such Future Parity Bonds; and (3) provide for the satisfaction of such Reserve Requirement (if any).

(c) The City must have on file with the City Clerk either:

   (1) a certificate of the Finance Director of the City, supported by the Electric Utility financial statements (which may or may not be audited), demonstrating that the Adjusted Net Revenue of the Electric Utility for any 12 consecutive months out of the 24 months preceding the dated date of the proposed bonds will be sufficient to satisfy the Coverage Requirement with respect to the Parity Bonds then outstanding, plus the Future Parity Bonds proposed to be issued; or

   (2) a certificate from an independent licensed professional engineer or engineering firm showing that in his, her or its professional opinion the Adjusted Net Revenue of the Electric Utility, which will be available in each succeeding year for the payment of principal of and interest on all Parity Bonds then outstanding and the Future Parity Bonds, will be sufficient to satisfy the Coverage Requirement with respect to the Parity Bonds then outstanding, plus the Future Parity Bonds proposed to be issued. Computation of estimated future Adjusted Net Revenue of the Electric Utility is to be based upon income and expense statements of the Electric Utility for any 12 consecutive months out of the 24 months preceding the dated date of the proposed bonds, plus additional adjustments, which may reflect: (i) any current changes in Net Revenue of the Electric Utility for the base period which would have occurred if the schedule of rates and charges in effect at the time of the computation (or approved by the City Council as of the time of such computation and to become effective within 30 days thereof) had been in effect during the portion of the period in which such schedule was not in effect; (ii) a full 12 months of revenue from any customers of the Electric Utility added prior to the computation date; (iii) the loss of customers since that period; (iv) any changes in Net Revenue of the Electric Utility estimated to be received as a result of, and upon completion of, any facilities under construction or to be acquired, constructed or installed as a part of the Electric Utility which are not reflected fully in the base period statement; and (v) annualized net revenue from the improvements to be financed from the proceeds of the proposed Future Parity Bonds.

(d) If the Future Parity Bonds proposed to be issued are for the sole purpose of refunding any Parity Bonds then outstanding, no certificate will be required, so long as the Maximum Annual Debt Service for the proposed Future Parity Bonds is less than the Maximum Annual Debt Service for the Parity Bonds to be refunded, and the final maturity of the proposed Future Parity Bonds is not extended beyond the final maturity of the Parity Bonds to be refunded.

Other Covenants

Maintenance and Operation. The City has covenanted in the Bond Ordinance that it will at all times maintain and keep the Electric Utility in good repair, working order and condition, and will at all times operate the Electric Utility, and the business in connection therewith, in an efficient manner and at a reasonable cost.

No Sale or Disposition of Electric Utility. The City has covenanted in the Bond Ordinance that it will not sell, lease, mortgage, or in any manner encumber or dispose of all, or substantially all, of the property of the Electric Utility unless provision is made for the payment into the Bond Fund of sums sufficient to pay the principal of and interest on the Parity Bonds then outstanding. Furthermore, it will not sell, lease, mortgage, or in any manner encumber or dispose of, in any year, more than 5% of the property of the Electric Utility that is used, useful and material to the operation thereof, unless provision is made for replacement thereof, or for payment into the Bond Fund of the total amount of the proceeds of such sales, leases, mortgages, encumbrances or dispositions. Any such money so paid into the Bond Fund is to be used to retire the Parity Bonds then outstanding at the earliest possible date. In addition, it will not contract with another entity operating an electric utility to surrender any substantial territory which the Electric Utility serves or plans to serve with electricity without replacing the Gross Revenue received, or expected to be received, from that territory with revenue from another source or other equivalent compensation.

Books and Accounts. The City has covenanted in the Bond Ordinance that it will keep proper and separate accounts and records in which complete and separate entries is to be made of all transactions relating to the Electric Utility, and it will furnish, at the written request of the owners of $1,000,000 in outstanding principal amount of the Bonds, complete operating and income statements of the Electric Utility in reasonable detail covering any calendar year not more than 90 days after the close of such calendar year. Upon request of any owner or owners of any of the Bonds, it will also furnish to such owner or owners a copy of the most recently completed audit of the City's accounts by the State Auditor, or such other audit as is authorized by law in lieu thereof.

No Free Service. The City has covenanted in the Bond Ordinance that, except to aid the poor and infirm consistent with the State constitution, it will not furnish municipal electric service to any customer (including the City) whatsoever free of charge and will promptly take legal action to enforce collection of all delinquent accounts.

Insurance. The City has covenanted in the Bond Ordinance that it will carry the type of insurance on its Electric Utility property in the amounts normally carried by private electric utility companies engaged in the operation of electric utility systems, or in the alternative, it may self-insure or, through an association of other municipalities, insure such property in similar amounts. The cost of such insurance or self-insurance shall be considered part of Operation and Maintenance Expenses of the Electric Utility.

Satisfy Other Electric Utility Obligations. The City has covenanted in the Bond Ordinance that it will pay, out of Gross Revenue, all Operation and Maintenance Expenses and the debt service requirements of the Parity Bonds, and will otherwise meet the obligations of the City as herein set forth.

Priority of Lien. The City has covenanted in the Bond Ordinance that it will not permit or enter into any obligation which is to have a prior or equal claim or lien on the Net Revenue of the Electric Utility except as permitted in the Bond Ordinance and in compliance with the Parity Bond Test.

Amendatory and Supplemental Ordinances

The City has covenanted not to amend or supplement the Bond Ordinance subsequent to the issuance of the Bonds, except as provided in and in accordance with the Bond Ordinance. See APPENDIX A—THE BOND ORDINANCE—Section 9.01.

Springing Amendments

The Bond Ordinance contains certain "springing" amendments that will become effective once the 2013B Bonds and 2015 Bonds are no longer outstanding, which is expected to occur prior to the final maturity date of the Bonds. This includes changes to the Reserve Requirement and Reserve Account and provisions regarding defaults and remedies. The owners of the Bonds by their purchase of such Bonds are deemed to have consented to these springing amendments. See "—The Bond Fund—*Reserve Account*," and APPENDIX A—THE BOND ORDINANCE—Sections 1.01, 5.03 and 9.02.

Outstanding Parity Bonds

Upon the issuance of the Bonds, the City will have the following Parity Bonds outstanding.

Table 1.
Summary of Outstanding Parity Bonds and the Bonds[1]

Bond Issue	Issue Date	Final Maturity Date	Original Par Amount	Amount Outstanding
Electric Revenue Improvement and Refunding Bonds, 2013B	5/16/2013	11/01/2023	$ 19,455,000	$ 690,000
Electric Utility Revenue Bonds, 2015	11/10/2015	11/01/2045	19,435,000	17,920,000
Electric Revenue Improvement and Refunding Bonds, 2018	4/05/2018	11/01/2047	19,800,000	13,455,000
Electric Revenue Improvement and Refunding Bonds, 2019A	12/19/2019	11/01/2044	12,525,000	11,705,000
Electric Revenue Bonds, 2019T (Taxable – Green Bonds)	12/19/2019	11/01/2033	3,145,000	3,145,000
Electric Revenue Bonds, 2021	11/23/2021	11/01/2046	6,415,000	6,415,000
The Bonds	6/06/2023	11/01/2053	19,415,000	19,415,000
Total Outstanding Parity Bonds and the Bonds				**$ 72,745,000**

(1) As of the Issue Date for the Bonds. Reflects the refunding of the Refunded Bonds.
Source: City of Richland

Future Parity Bonds

The City anticipates issuing approximately $18.9 million of additional Parity Bonds over the next six years. See "THE ELECTRIC UTILITY—Future Financing Plans" below for a description of the financing needs projected in the City's long-term capital improvement plan. The City periodically reviews its outstanding bonds for refunding opportunities and may issue Parity Bonds for refunding purposes if market conditions warrant.

Subordinate Debt

The City has no outstanding subordinate debt of the Electric Utility. The City reserves the right to issue subordinate debt of the Electric Utility under the terms of the Bond Ordinance. See APPENDIX A—THE BOND ORDINANCE —Section 7.05.

Debt Payment Record

The City has promptly met all debt service payments on outstanding obligations. No refunding bonds have been issued to avoid an impending default.

Debt Service Requirements

Debt service requirements for the Outstanding Parity Bonds and the Bonds are shown in Table 2 on the following page.

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Table 1.
Parity Bond Debt Service Requirements[1]

Year	Outstanding Parity Bonds [2] Principal	Outstanding Parity Bonds [2] Interest	The Bonds Principal	The Bonds Interest	Total Debt Service Requirements
2023	$ 2,295,000	$ 2,584,944	$ -	$ 390,997	$ 5,270,941
2024	1,665,000	2,187,796	770,000	970,750	5,593,546
2025	1,720,000	2,129,997	805,000	932,250	5,587,247
2026	1,785,000	2,069,730	845,000	892,000	5,591,730
2027	1,860,000	1,994,190	885,000	849,750	5,588,940
2028	1,920,000	1,915,030	940,000	805,500	5,580,530
2029	2,010,000	1,832,847	985,000	758,500	5,586,347
2030	2,095,000	1,746,387	1,025,000	709,250	5,575,637
2031	2,180,000	1,664,430	1,080,000	658,000	5,582,430
2032	2,270,000	1,577,857	1,135,000	604,000	5,586,857
2033	2,360,000	1,484,917	1,190,000	547,250	5,582,167
2034	3,195,000	1,385,250	515,000	487,750	5,583,000
2035	3,325,000	1,252,938	545,000	462,000	5,584,938
2036	3,470,000	1,113,175	565,000	434,750	5,582,925
2037	2,260,000	965,175	595,000	406,500	4,226,675
2038	2,370,000	858,350	625,000	376,750	4,230,100
2039	2,485,000	746,275	655,000	345,500	4,231,775
2040	2,025,000	628,675	685,000	312,750	3,651,425
2041	2,125,000	534,013	715,000	278,500	3,652,513
2042	2,215,000	434,638	760,000	242,750	3,652,388
2043	2,315,000	335,631	290,000	204,750	3,145,381
2044	2,425,000	232,113	300,000	190,250	3,147,363
2045	1,930,000	123,225	320,000	175,250	2,548,475
2046	710,000	39,625	335,000	159,250	1,243,875
2047	320,000	12,000	350,000	142,500	824,500
2048	-	-	370,000	125,000	495,000
2049	-	-	385,000	106,500	491,500
2050	-	-	405,000	87,250	492,250
2051	-	-	425,000	67,000	492,000
2052	-	-	445,000	45,750	490,750
2053	-	-	470,000	23,500	493,500
Total	**$ 53,330,000**	**$ 29,849,207**	**$ 19,415,000**	**$ 12,792,497**	**$ 115,386,703**

(1) Totals may not add due to rounding.
(2) Excludes debt service on the Refunded Bonds. See the captions "USE OF BOND PROCEEDS—Uses of Bond Proceeds and Plan of Refunding" and "—Outstanding Parity Bonds."

THE ELECTRIC UTILITY

Description of the Electric Utility

The City acquired its electric system (the "Electric Utility") in 1959 when ownership was transferred to the City by the United States Government. The Electric Utility is currently operated by the City's Energy Services Department and, as of December 31, 2022, served approximately 25,444 residential customer accounts with over 28,858 total active meters. The Electric Utility's service area encompasses 48 square miles, 41.8 square miles of which are within City limits.

The City is a load-following customer of the Bonneville Power Administration ("Bonneville") for substantially all of its wholesale power and transmission services. The Electric Utility receives power from Bonneville at nine points of delivery (substations): Snyder, First Street, Stevens Drive, Thayer Drive, Richland Switch, Sandhill Crane, City View, Tapteal, and Leslie Road. See "POWER SUPPLY AND TRANSMISSION—Power Supply—*Bonneville Power Administration,*" below. These substations are served from Bonneville's 115,000 Volt (115 kiloVolts, or "kV") transmission system. The Electric Utility owns and operates the transformers and distribution facilities at all ten substations. The nameplate capacity of the total transformation facilities serving the Electric Utility's distribution system is 453 Megavolt-Ampere ("MVA"). The distribution facilities contain seventy-nine 12,470/7,200-Volt feeders which have a nominal 465 ampere capacity each. These feeders are operated as radial lines but have the capability of being looped for maintenance and emergency situations. The distribution system contains approximately 147 circuit miles of overhead distribution lines and 472 miles of underground distribution cable.

Planned capital improvement projects will add one additional substation: City View Bank 2 addition, as well as substation transformer and switchgear replacement at Stevens Bank 1 and Thayer Bank 1. See "—Capital Improvement Plan," below. The addition of the substation and transformer replacements will also increase the Electrical Utility capacity rating by 58 MVA.

The Electric Utility has entered into service area agreements with two neighboring utilities: Public Utility District No. 1 of Benton County and Benton Rural Electric Association, which currently extend through 2030. The agreements define the boundaries for electric utility service, encourage the orderly expansion of the Electric Utility's service into the City's Urban Growth Area, and establish compensation for the sale and transfer of electric facilities between utilities.

Governance and Management

The City Council has responsibility for, among other things, establishing budgets and rates. See "—Rates and Charges" below.

A Utility Advisory Committee (the "Committee") was created by the City to make available to the City Council additional expertise relative to the operating and management policies of City-owned utilities, including the Electric Utility. The Committee is composed of seven members appointed by the City Council. The Committee's role is advisory and does not limit the City Council's authority over rate setting.

The Electric Utility is managed by an Energy Services Director who is appointed by the City Manager. A brief description of relevant experience of the Energy Services Director follows.

Clint Whitney, Energy Services Director, assumed the role of Energy Services Director in 2018. Mr. Whitney joined the City as an Electrical Distribution Engineer in 1997. He has worked in a variety of positions with the City, including Electrical Systems Supervisor, Chief Electrical Engineer, and Engineering & Operations Manager. Mr. Whitney has a Bachelor of Science in Electrical Engineering and a Master of Business Administration, both from Washington State University. He is a registered Professional Engineer in Washington.

Electric Utility Employees

The Electric Utility has 55 full-time equivalent employees ("FTE"), as of May 10, 2023. The International Brotherhood of Electrical Workers (the "IBEW") represents 24 employees and the International Union of Operating Engineers (the "IUOE") represents 2 employees within the Electric Utility. The current IBEW contract expires on December 31, 2023 and the IUOE contract expires on December 31, 2024. See "THE CITY—Employees and Bargaining Groups" for a discussion of the City's relations with its labor unions.

Utility Taxes

City Utility Tax. The City is authorized to collect a utility tax on gross revenue from retail electricity sales of the Electric Utility, less certain adjustments. The Electric Utility passes this tax to its customers, collecting it through the customer's bill as part of the established customer rates and charges, for payment to the City's General Fund. A tax rate of 8.5% was approved by the voters in 1996, permitting a rate in excess of the otherwise applicable statutory maximum rate. See "—Rates and Charges" below.

State Public Utility Tax. The Electric Utility also pays a public utility tax to the State at a rate of 3.8734% of gross revenues of the Electric Utility. For purposes of the State public utility tax, "gross revenues" is defined by State law and includes amounts collected for the City utility tax.

Rates and Charges

The ordinances authorizing the issuance of the Outstanding Parity Bonds require the City to establish, maintain, and collect rates and charges for electric power and energy and other services to provide revenues sufficient for the punctual payment of the principal of, premium (if any), and interest on all outstanding debts, to pay for the proper operation and maintenance expenses of the Electric Utility, and to make all necessary repairs, replacements and renewals thereof.

Rates are generally applicable and uniformly applied within each customer class. Under State law, the City Council has the exclusive authority to set rates and charges for electric energy and services and this authority is not subject to review or control by any federal, state, or local agency.

The Electric Utility has adjusted its rates when needed, primarily as a result of increased wholesale power cost from Bonneville. The City's most recent retail rate adjustment was effective August 4, 2020, representing only an adjustment to the Cable Television Amplifier/Small Cell rate. Prior to the increase in 2020, the last retail rate adjustment occurred on June 1, 2019, representing an average increase of 8% across all rate classes. No additional rate increases have since been adopted.

The City has 12 rate classes, the largest of which are residential, commercial/general services, industrial, irrigation, and rental/street lighting. Residential customers make up approximately 88.2% of total number of customers (measured by meter count), at basic charge rates of $0.69/day for single-phase service, $0.98/day for multi-phase service in addition to $0.0741/kWh for the energy consumption charge. These charges generate approximately 49% of Electric Utility power sales revenue. Descriptions of rate schedules for other customer classes are set forth in the Richland Municipal Code ("RMC"), Section 14.24.060 and were last revised by Ordinance No. 15-20, which adopted rates that went into effect as of August 4, 2020.

Table 3, below, shows the average annual system revenue in dollars per megaWatt-hour ("MWh"), and corresponding customer class/group average annual unit rate revenue.

Table 2.
Average Annual Retail Rate Revenue History
(Unaudited) ($ per MWh)

	Average Annual Electric Utility	**Average Annual Revenue per MWh by Customer Type(1)**		
Year	**Rate Revenue per MWh**	**Residential**	**Commercial(2)**	**Industrial(3)**
2013	57.26	70.95	48.42	45.90
2014	57.06	71.03	48.26	45.25
2015	58.29	69.97	50.12	45.73
2016	61.89	79.74	53.28	46.94
2017	66.44	83.93	56.20	50.08
2018	65.68	84.44	55.82	49.51
2019	74.42	87.53	59.17	55.40
2020	71.99	91.38	61.26	56.55
2021	72.60	91.04	61.54	55.83
2022	72.43	90.34	62.41	56.76

(1) $ per MWh is calculated as rate revenue per customer type divided by MWh sales per customer type.
(2) Commercial includes Small, Medium and Large General Service rate classes.
(3) Industrial incudes Small Industrial, Large Industrial and Irrigation rate classes.

Source: City of Richland

Comparison of Monthly Electric Bills

The following table compares the City's monthly electric rates and charges ("bills") for selected comparable residential, commercial and industrial loads with those of other local and major public and private Pacific Northwest utilities. The representative monthly electric bills shown are based on comparable customer types and usage profiles, and on the specific rate schedules for each utility. Use of different schedules applicable to particular customers would yield different results.

Table 3.
Comparative Sample Monthly Electric Bills[(1)]
(As of January 1, 2023)

	Residential[(2)]	Commercial[(3)]	Industrial[(4)]
Chelan County Public Utility District	$ 46.70	$ 4,296.90	$ 47,385.00
Grant County Public Utility District	76.11	4,826.86	69,411.00
Benton County Public Utility District	111.54	9,036.64	123,086.00
The City [(5)]	**113.61**	**7,857.14**	**112,454.00**
Franklin County Public Utility District	118.13	8,872.76	127,287.00
Pacific Power	130.19	11,628.00	169,546.00
Average (excluding the City)	*$ 96.54*	*$ 7,732.24*	*$ 107,343.00*

(1) There are variations in rate schedules and rate classifications used by the various utilities. Some rates include city, state or other local utility tax. All utilities except Pacific Power are municipal utilities; Pacific Power is an investor-owned utility subject to regulation by the Washington Utilities and Transportation Commission.
(2) Estimates are based upon 1,250 kWh monthly use, year-round.
(3) Estimated based upon 400 kW demand and 130,000 kWh monthly use.
(4) Estimated based upon 5,000 kW demand and 2,000,000 kWh monthly use.
(5) City rates shown above include the amounts necessary to pay City-imposed utility taxes and State public utility taxes. See "—Utility Taxes" above.

Source: Compiled by City of Richland, using rate schedules posted on the websites of the utilities listed.

Historical Information on Customers and Electricity Sales

The tables below show the calendar year-end number of meters and electricity sales by customer class for the Electric Utility for the years 2018 through 2022. The number of active meters shown below may differ from the number of customers in each category because some customers have multiple metered accounts.

Table 4.
Historical Number of Active Customer Meters

Category	2018	2019	2020	2021	2022[(1)]
Residential	24,354	24,809	24,870	25,094	25,421
Commercial/General Services	2,724	2,745	2,790	2,830	2,838
Industrial	7	12	10	12	12
Irrigation	104	105	107	101	101
Rental/Street Lighting	401	401	401	401	401
Miscellaneous	57	56	57	57	57
Total	27,647	28,128	28,235	28,495	28,830

(1) Unaudited.

Source: City of Richland

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Table 5.
Historical Power Sales (MWh) and Peak Demand (MW)

Power Sales (MWh)	2018	2019	2020	2021	2022[1]
Residential	338,631	367,064	348,079	360,012	389,130
Commercial/General Services	429,645	415,476	377,347	389,856	384,493
Industrial	136,354	105,873	156,363	172,781	180,587
Irrigation	21,068	16,830	18,210	22,327	18,360
Rental/Street Lighting	4,898	4,580	4,722	4,307	4,299
Miscellaneous	1,288	1,283	1,341	1,668	1,660
Total	931,884	911,106	906,062	950,951	978,529
Peak Demand (MW)	190.6	215.7	197.6	211.8	204.0

(1) Unaudited.
Source: City of Richland

Table 6.
Historical Power Sale Revenues[1]

Power Sales	2018	2019	2020	2021	2022[2]
Residential	$ 28,592,485	$ 32,130,708	$ 31,806,860	$ 32,776,694	$ 35,153,758
Commercial/General Services	24,068,033	24,584,191	23,206,572	23,992,496	23,996,857
Industrial	6,751,122	8,244,656	8,619,064	9,442,096	10,030,090
Irrigation	1,305,714	1,153,210	1,253,723	1,451,058	1,263,319
Rental/Street Lighting	493,535	495,741	486,317	486,212	494,335
Miscellaneous	80,183	81,624	86,584	107,007	106,509
Total	$ 61,291,072	$ 66,690,130	$ 65,459,120	$ 68,255,563	$ 71,044,868

Totals may not add due to rounding.
(1) Excludes amounts collected in respect of City- and State-imposed utility taxes. See "—Utility Taxes" above.
(2) Unaudited.
Source: City of Richland

Largest Customers

The Electric Utility's 10 largest customers for the year ending December 31, 2022, used a combined aggregate of 341 MWh of power, paid approximately $20.3 million in revenues, and accounted for approximately 28.5% of total power sales. In 2022, the Electric Utility's four largest customers, ConAgra Foods (a frozen food processor), Pacific Northwest National Laboratories ("PNNL") (a U.S. Department of Energy ("DOE") national research laboratory managed by Battelle), Framatome (a nuclear fuel production facility), and City of Richland (a municipal government), when combined, accounted for approximately 19.4% of total power sales. The Electric Utility has no special output contracts with these or any other customers.

Table 7.
2022 Top Ten Customers by Power Sales Revenue

Name[1]	Total Power Sales	Total MWh	% of Total Power Sales
Lamb Weston	$ 5,284,584	89,475	7.44%
Battelle Pacific NW	4,734,766	80,581	6.66
Areva NP Richland	2,064,635	35,492	2.91
City of Richland	1,692,622	25,288	2.38
ATI Richland Operations	1,527,513	24,746	2.15
Preferred Freezer	1,354,074	22,802	1.91
Richland School District	1,273,455	18,655	1.79
Kadlec Hospital	1,021,278	24,008	1.44
Badger Mountain Irrigation	736,029	10,066	1.04
NOTUS Holdings	579,065	9,793	0.82
Total	**$ 20,268,021**	**340,906**	**28.53%**
All others	**$ 50,776,847**	**637,623**	**71.47%**

(1) See "GENERAL AND ECONOMIC INFORMATION — Economic Development" for a discussion of recent business activities of many of these customers.

Source: City of Richland

Financial Policies

A summary of the City's city-wide Financial Policies and Guidelines is set forth in the City's 2023 Budget document available on its website. On December 19, 2017, the City Council approved Resolution 225-17, setting forth a Debt Management Policy for the City.

Capital Improvement Plan

The City's current capital improvement plan ("CIP") addresses anticipated capital needs for the Electric Utility for years 2023 through 2028. The City expects to fund the 2023-2028 CIP with approximately $18.9 million in revenue bonds (including the Bonds) and a combination of facility fees and retail rate revenues.

Table 8.
Electric Utility Capital Improvement Plan (2023-2028)

Project	2023	2024	2025	2026	2027	2028
Southwest Service Area Infrastructure Acquisition	$ 212,000	$ -	$ -	$ -	$ -	$ -
System Improvements	786,000	990,000	792,000	784,000	107,000	500,000
Renewal & Replacement	2,562,000	3,356,000	3,494,000	3,469,000	2,867,000	1,800,000
Adv. Metering Infrastructure	-	-	-	-	-	-
Substation Improvements	4,929,000	3,688,000	407,000	2,877,000	2,554,000	2,500,000
Dallas Rd Substation	-	1,325,000	5,144,000	-	-	-
Leslie Rd Substation	-	-	-	-	-	-
Fusion Substation	530,000	-	1,362,000	2,846,000	-	-
Gateway Substation	-	675,000	506,000	253,000	-	-
Line Extensions	2,120,000	2,004,000	2,004,000	2,004,000	2,004,000	1,000,000
Total by Years	**$11,139,000**	**$12,038,000**	**$13,709,000**	**$12,233,000**	**$7,532,000**	**$5,800,000**

Source: City of Richland

Future Financing Plans

For the 2023 through 2024 period of CIP projects, approximately 34.5% (approximately $8 million of $23.2 million) is expected to be financed with proceeds of the Bonds and the remaining is expected to be rate-financed. For the 2023-2028 period of CIP projects, approximately 30.2% ($18.9 million of $62.5 million) is expected to be bond-financed and the remaining rate-financed. Future Parity Bonds must be issued in accordance with the Parity Bond Test and must be authorized by the City Council. See "SECURITY AND SOURCES OF PAYMENT—Future Parity Bonds," above.

POWER SUPPLY AND TRANSMISSION

Power Supply

The Electric Utility is a statutory preference customer of Bonneville and currently purchases almost all of its power under a long-term power supply contract that went into effect in 2011. See "—*Bonneville Power Supply Contract*" below. The City has a power purchase agreement for non-federal renewable energy with Horn Rapids Solar, Storage and Training ("HRSST"), which is described in detail below. See "—Resource Planning—*Integrated Resource Planning and Renewable Portfolio Standards*" below.

Bonneville Power Administration. Bonneville was created by federal law in 1937 and is a revenue-financed federal agency under the DOE. Bonneville markets power from the Federal Columbia River Power System (the "Federal Base System" or "FBS"), composed of 31 federal hydroelectric projects, one non-federal nuclear project, several non-federal hydroelectric, wind, and thermal projects in the Pacific Northwest, and via various exchange and market contractual arrangements. The FBS has firm nameplate peak generating capacity of approximately 17,400 MW and firm energy capability of approximately 9,871 average MW. The FBS, located primarily in the Columbia and Snake River Basins, are owned and operated by the United States Bureau of Reclamation and the United States Army Corps of Engineers. The FBS currently produces more than one-third of the region's energy requirements. Bonneville's transmission system includes over 15,000 circuit miles of high-voltage lines, provides approximately 65% of the Pacific Northwest's bulk transmission capacity and serves as the region's main power grid.

Bonneville sells electric power (energy and capacity) at cost-based wholesale rates to more than 125 publicly-owned and cooperatively-owned utilities for resale to consumers in the Pacific Northwest. Bonneville also sells electric power to a small number of federal agencies and has the authority, but not the obligation, to sell to both investor-owned utilities and direct service industry customers. Its service area covers over 300,000 square miles and has a population of about 14 million.

Bonneville is required by law to meet certain energy requirements in the region and is authorized to acquire power resources and take other actions to enable it to carry out these purposes. This includes the requirement for Bonneville to provide power to preference customers, like the City's Electric Utility, so the utility can meet its total customer load and load growth, less its owned or purchased resources from non-federal generators. In doing so, Bonneville must give preference and priority to consumer- and publicly-owned utilities ("preference customers") before offering to serve non-preference entities. Since 1937, Bonneville has always met its power marketing obligations to supply federal power to serve the firm power needs of its regional power customers.

Bonneville has four divisions: Power Services; Transmission Services; Environmental/Fish & Wildlife; and Corporate Services. Power Services and Transmission Services are separate entities managerially and financially.

Bonneville Power Supply Contract. By virtue of federal legislation, the City and other publicly owned utilities and cooperatives are preference customers of Bonneville, granting them priority access to FBS power. Bonneville restructured its long-term power supply contracts to shift responsibility toward utilities to serve their own load growth and predicated its new long-term power supply agreements on a Tiered Rate Methodology ("TRM"). The TRM establishes Tier 1 and Tier 2 resources, the former equating to the amount of power generated by the FBS and the latter being market-based, as well as related tiered power rate designs. Bonneville's customers, including the City, signed the new power supply agreements in 2008 for the effective term beginning in October 2011 through September 2028.

In anticipation of the expiration of the Long-Term Preference Contracts and other agreements at the end of Fiscal Year 2028, Bonneville is expected to engage its customers through a public process to determine the character of Bonneville's long-term power sales commitments in the region and Bonneville's long-term role in meeting regional power needs beginning in 2029. Bonneville engaged in discussions on key issues and held public workshops 2022 to discuss proposals. Bonneville is currently expected to release a policy and related record of decision in 2023 or 2024, and execute new long-term power sales contracts and other agreements in Fiscal Year 2026.

The Electric Utility's current long-term power supply agreement with Bonneville reflects a take-or-pay load-following obligation whereby Bonneville supplies the City's hourly requirements in excess of the City's Tier 2 resources. The amount of power that preference customers (including the Electric Utility) may purchase under Bonneville's lowest cost rate (the "Tier 1 Rate") is limited to an amount equal to the generating output of the current FBS, with some limited amounts of augmentation, and was fully allocated among the preference customers on the basis of historical actual net requirements in a defined period prior to Federal Fiscal Year ("FFY") 2011. Preference customer load in excess of Tier 1 allocations constitutes Tier 2 load and can be served from non-federal resources or purchased from Bonneville at a Tier 2 Rate, reflecting the incremental cost to Bonneville of obtaining additional power to meet such incremental load. Under the agreement, Bonneville has broad rights to require that preference customers post collateral in relation to Tier 2 purchases. However, Bonneville has never required the City to post collateral in the past and the City does not expect to be required to post collateral in the future.

The Electric Utility currently purchases greater than 92% the power it receives under the Bonneville contract at the Tier 1 Rate. From FFY 2011 through 2022, the City met its Tier 2 requirements using a mix of non-federal power and firm power purchased through Bonneville at Tier 2 Rates. Beginning in October 2023 and continuing through September 2028, the City will meet its Tier 2 requirements by using a mix of non-federal power and firm power purchased through Bonneville at Tier 2 Rates and power purchase agreements. See "—Resource Planning—*Bonneville Tier 2 Requirements Purchases*" below.

Bonneville Power Supply Rates. Bonneville is required by federal law to recover all of its net costs through the power and transmission rates it charges its customers and to make various rate filings with the Federal Energy Regulatory Commission ("FERC"). Under the current power supply contracts, Bonneville conducts a rate case every two years, but the rates are subject to a cost recovery adjustment clause that allows power rates to increase during a two-year rate period if certain events occur. Bonneville increased the FFY 2019-2020 Tier 1 rates by an average net cost increase of 5.0%, not including transmission costs. In July 2021, Bonneville published its FFY 2022-2023 wholesale energy rates which represent an average annual decrease of 1% for the City. Rate proceedings for 2024-2025 rate period have begun and a final rate proposal is expected by the end of July 2023.

There are many factors that have impacted and could impact Bonneville's cost of service and rates, including federal legislation, Bonneville's obligations regarding its outstanding federal debt, number of customers, water conditions and climate change, endangered species and other environmental regulations, capital needs of the FBS, outcome of various litigation, regional transmission issues, natural gas prices, and the economy. Any factors that impact Bonneville's cost of service would impact the costs paid by the Electric Utility.

Certain Factors Affecting Bonneville Rates. The meteorological effects of climate change could affect the generation capability of Bonneville to meet the loads of its power purchasers, including the Electric Utility. Bonneville's generating capacity is reliant on precipitation and snowpack. Climate change could affect the amount, timing and availability of hydroelectric generation, which could result in increased costs to the Electric Utility.

Endangered Species Act. Since 1991, various salmon species in the Columbia River Basin have been listed as threatened or endangered under the Endangered Species Act ("ESA"). Under the ESA, federal agencies must ensure that their actions are not likely to jeopardize the continued existence of these species or result in the destruction or adverse modification of their critical habitat. In view of these listings, Bonneville, the United States Bureau of Reclamation and the United States Army Corps of Engineers have undertaken measures to protect salmon that have resulted in a reduction in the amount of firm power and energy available for sale by Bonneville. These measures also have resulted in significant increases in expenditures by Bonneville.

In May 2016, U.S. District Court Judge Michael Simon ruled that the federal plan to restore the salmon population, or Biological Opinion ("BiOp") does not comply with the ESA and the National Environmental Policy Act ("NEPA"). In his ruling he ordered the federal agencies to prepare a new BiOp and another comprehensive analysis, including evaluation of additional alternatives. The federal agencies issued a draft on the environmental impact statement ("EIS") on Feb 28, 2020 and released the final EIS on July 28, 2020. The joint Record of Decision was issued on September 28, 2020. Under the new EIS, Bonneville will use the CRSO EIS for any operational changes associated with power marketing. These changes will follow compliance with applicable laws and regulations, including the NEPA, the ESA, the Pacific Northwest Electric Power Planning and Conservation Act and the CWA

Columbia River Treaty Renegotiation. In 1964, the United States and Canada signed a treaty (the "Treaty") with terms for the operation of storage in upstream Canadian Reservoirs for the benefit of both the Pacific Northwest and Canada. The Treaty's flood risk and hydropower operations provide substantial benefits to Canadians and those living in the Columbia River's drainage basin, including Washington, Oregon, Idaho, Montana, Utah, Wyoming, and British Columbia. The Treaty also includes financial entitlements for Canada that may be renegotiated to better match the benefits provided for each party. The Treaty has also facilitated additional benefits such as supporting the ecosystem of the Columbia River, irrigation, municipal water use, industrial use, navigation, and recreation. The Treaty's computation of energy benefits that result from the Canadian improvements to upstream storage is of particular interest to utilities because it creates an energy return obligation (the "Canadian Entitlement") for U.S. operators of Columbia River dams, including Bonneville. Although the Treaty does not expire by its own terms, either the U.S. or Canada may elect to terminate it by providing not less than ten years' notice. The United States Department of State began renegotiating the Treaty in 2018. The twelfth round of negotiations was held in January 2022. During this round, the United States and Canada discussed post-2024 flood risk management, Canada's desire for more operational flexibility, and mechanisms for achieving ecosystem objectives. The new Treaty terms are expected to affect hydroelectric generation and each of the benefits listed, although the effects on Bonneville and power costs are not known at this time.

Energy Northwest. Energy Northwest is a municipal corporation and a joint operating agency organized and existing under the laws of the State. It has the authority to acquire, construct, and operate works, plants, and facilities for the generation and transmission of electric power and energy. The membership of Energy Northwest includes 27 member utilities, all located in the State.

Energy Northwest's Columbia Generating Station nuclear plant is included with Bonneville's federal facilities for purposes of integrated resource planning and operation. Bonneville markets power from and is responsible for paying the capital costs of certain Energy Northwest nuclear projects and other non-federal projects.

The City is a member of Energy Northwest, a participant in Energy Northwest's Nuclear Projects Nos. 1, 2, and 3 and the Hanford Generating Project. Project No. 2 is operating while the remaining projects have been terminated. The City, Energy Northwest, and Bonneville have entered into separate Net Billing Agreements with respect to the outstanding bonds for Energy Northwest's Project No. 1, Project No. 2, and 70% ownership share of Project No. 3 (collectively, the "Net Billed Projects") under which the City has purchased from Energy Northwest and, in turn, assigned to Bonneville a maximum of 1.83%, 2.78%, and 1.59% of the capability of Projects No. 1, 2, and Energy Northwest's ownership share of Project No. 3, respectively. Under the agreements, the City is unconditionally obligated to pay Energy Northwest its pro rata share of the total costs of the projects, including debt service. Under the Net Billing Agreements, Bonneville is responsible for the City's percentage share of the total annual cost of each project, including debt service on revenue bonds issued to finance the costs of construction. In 2006, Bonneville and Energy Northwest entered into an agreement pursuant to which Bonneville pays directly to Energy Northwest the costs of each project rather than net billing participants such costs. The City's electric revenue requirements are not directly affected by the cost of the Net Billed Projects. In the direct pay agreements, Energy Northwest agrees to promptly bill the City and other participants their share of the costs of the respective project under the Net Billing Agreements if Bonneville fails to make a payment when due under the direct pay agreements. The revenue requirements are affected only to the extent that the costs of the projects result in increases in Bonneville's wholesale power rates or if Bonneville fails to pay. Bonneville has not failed in the past to make payments under this agreement.

Energy Northwest has for the past several years been actively restructuring the debt payment related to the above-referenced nuclear projects, thereby resulting in substantial Bonneville customer rate relief.

Transmission Facilities and Services

Bonneville Transmission Services. The Electric Utility owns approximately 8 miles of transmission line with Bonneville providing all protective relaying responsibility from Bonneville substations. Historically, Bonneville provided bundled electric power and transmission services under the power supply contracts. Certain FERC regulatory changes required Bonneville to unbundle its electric power transmission services and now requires the purchase of transmission services separately. To obtain needed transmission services, the City entered into a Network Integration Transmission Services Agreement with Bonneville expiring October 1, 2031. The City's peak transmission demand during calendar year 2022 was 205.2 MW.

Bonneville Transmission Rates. Bonneville's transmission rates remained largely unchanged for about a decade prior to Bonneville's FFY 2014 rate case, which implemented a 9.3% increase in network transmission ("NT") rates, followed by another 4.4% in its FFY 2016 rate case. Bonneville's FFY 2018 rate case resulted in a decrease of 0.7% in NT rates. Bonneville's FFY 2020 rate case resulted in an increase of 3.6% for NT rates. Bonneville's FFY 2022 rate case resulted in an increase of 9.5% for NT rates, this is in addition to the rate increases mentioned separately for wholesale power supply costs.

Bonneville has implemented several policies and strategies over the past several years that currently have and/or will have a positive rate impact for NT customers, including, but not limited to, third party leasing for some new construction builds, as well as affirming and planning for future NT projected load growth. There are several factors that have and could impact Bonneville's NT cost of service and rates, including federal legislation, Bonneville's obligations regarding its outstanding federal debt, number of customer utilities, water conditions, new environmental regulations, outcome of various litigation, and regional transmission issues.

Resource Planning

Bonneville Tier 2 Requirements Purchases. By contract, Bonneville must deliver at cost the Electric Utility's Tier 1 resource needs with any excess need (Tier 2 power) being the full responsibility of the Electric Utility to secure. The Electric Utility's most recent load forecast submitted to Bonneville in February 2023 indicates that the Electric Utility's Tier 2 resource need currently comprises about 6% of its total resource need and is projected to grow to approximately 10% of the total Electric Utility resource need by 2033.

To meet Tier 2 resource needs in FFY 2022 and 2023, the Electric Utility, through its affiliation with Northwest Energy Management Services ("NEMS") and Northwest Intergovernmental Energy Supply ("NIES"), negotiated fixed-price purchases from TransAlta and a small portion from Columbia REA to supplement short-term market purchases from Bonneville. In addition, the Electric Utility secured a power purchase agreement with TUCCI Energy for output from 4MW renewable solar as part of the HRSST site. The 4MW solar equates to an average of 0.582 MW. With continuing industry decarbonizing efforts, the City expects to utilize Tier 2 resources purchased from Bonneville beginning in 2024, instead of other non-federal generation assets with unknown carbon impacts.

Integrated Resource Planning and Renewable Portfolio Standards. Under State law (RCW 19.280), all electric utilities are required to develop or update their resource plans and submit them to the State Department of Commerce every two years. The City most recently filed an Integrated Resource Plan ("IRP") in August 2020 and an updated status coversheet in September 2022. The Integrated Resource Plan includes a clean energy action plan to meet new requirements of amendments to chapter 19.280 RCW that were enacted in May 2019.

The City's IRP is intended to help it decide how to meet future load growth. The City currently utilizes the HRSST facility as a dedicated 0.582aMW renewable resource to support a portion of the City's future renewable portfolio standard requirement. In addition, the Electric Utility's resource planning and energy conservation activities are expected to be responsive to the conservation targets dictated by the Regional Power Council's Eighth Power Plan and by the State's Energy Independence Act (Initiative 937). See "—Clean Energy Laws and Regulations—*Energy Independence Act (Initiative 937) Renewable Portfolio Standards*" below.

Conservation. As a low cost resource, energy conservation is expected to continue to play a key role in minimizing power purchases. Since 2007, the Electric Utility has maintained an energy conservation program serving all segments of the customer base. Bonneville has identified City energy efficiency projects between 2012 and 2022 have reduced annual utility energy consumption by 7.61 MWh.

The City has a low-interest revolving loan program which offers residential and small commercial Electric Utility makes rebates available for the purchase of qualifying equipment, lighting, Energy Star home certification and similar activities. Considerable effort is made to assist larger commercial and industrial customers to obtain cost-sharing funds through Bonneville. The Electric Utility's combined loan and rebate conservation spending was approximately $828,000 in 2022. A Conservation Potential Assessment conducted by the City in September 2021 identified additional conservation measures best suited to be applied in each customer category and has been used to guide the City's current conservation program objectives.

Clean Energy Laws and Regulations

Energy Independence Act (Initiative 937) Renewable Portfolio Standards. State Initiative 937, which was approved in 2006 and subsequently passed into law and codified as chapter 19.285 RCW, Energy Independence Act (the "EIA"), required electric utilities that serve more than 25,000 customers ("qualifying utilities") to obtain at least: (i) 3% of their electricity from renewable resources by January 1, 2012, and each year thereafter through December 31, 2015; (ii) 9% of their electricity from renewable resources by January 1, 2016, and each year thereafter through December 31, 2019; and (iii) 15% of their electricity from renewable resources by January 1, 2020, and each year thereafter. For those utilities with fewer than 25,000 customers that later qualify after the date the law was adopted, the same incremental time periods apply for meeting the renewable resource percentage levels. Such utilities have four years from the qualifying date to obtain 3%, another four years to obtain 9%, and another four years to obtain 15% renewable resource targets. The EIA also requires qualifying electric utilities to undertake various cost-effective energy conservation efforts.

The Electric Utility became a qualifying utility under the EIA in January 2021, when its customer base surpassed the 25,000 customer threshold.

The Electric Utility currently obtains most of its power from hydropower, most of which is not defined as an eligible renewable resource under the EIA. A small portion of hydropower production due to efficiency improvements at the federal hydroelectric dams qualifies as eligible due to the EIA amendments enacted in May 2019. Since the Electric Utility became a qualifying utility, it is required to pursue renewable resources such as wind, solar, biomass, or other renewable resources eligible under the EIA. The City's updated Integrated Resource Plan was completed and adopted by City Council in August 2020. To help the City meet its renewable resource requirements, the City approved a 25-year Power Purchase Agreement with Tucci Energy Services for 0.582aMW of solar energy from the HRSST site. The HRSST became operational October 2020.

The EIA also requires qualifying electric utilities to undertake various cost-effective energy conservation efforts. The City obtains 0.582aMW from the HRSST project, which counts toward the EIA requirements. The City's updated Conservation Potential Assessment ("CPA") was completed in 2019. The CPA plan will be updated biennially as required by the EIA. See "—Resource Planning—*Integrated Resource Planning and Renewable Portfolio Standards*" above.

State Clean Energy Transformation Act (2019). The Washington State Clean Energy Transformation ACT ("CETA"), Chapter 19.405 RCW enacted in May 2019 establishes new carbon-free generation requirements for electric utilities. CETA requires electric utilities to eliminate coal-fired resources from their portfolio by December 31, 2025 and be greenhouse gas neutral by January 1, 2030. It establishes a standard for consumer-owned electric utilities to meet 100% of their retail electrical load using non-emitting electric generation and electricity from renewable resources by January 1, 2045. CETA requires each electric utility to submit a clean energy implementation plan ("CEIP") to the Washington State Department of Commerce beginning January 1, 2022, and every four years until 2045. The City Council approved its CEIP in October 2021. The City will use its CEIP and Integrated Resource Plan to guide its decisions about complying with CETA.

Climate Commitment Act (2021). The Climate Commitment Act (CCA) enacted in May 2021 requires Washington State to achieve net zero emissions by 2050. It creates a "cap and invest" program, which sets a statewide cap on greenhouse gas emissions and then auctions or allocates emissions allowances to fuel suppliers, industrial sources, electricity generators, and other large sources of emissions. Each allowance is an authorization to emit up to one metric ton of carbon dioxide equivalent (CO_2e). The cap decreases over time and causes emitters to increase efficiency, improve processes, switch to non-emitting technologies, or support programs that reduce or capture carbon emissions. The "invest" part of the program refers to proceeds from the auction of emissions allowances, which will support climate resiliency programs, such as flood mitigation, securing water supplies, and clean energy projects.

Allowances will be allocated at no cost to electric utilities subject to CETA to mitigate the cost burden of the program on electric utility customers. The allocations will be consistent with the utility's supply and demand forecast and the cost burden resulting from the inclusion of the covered entities in each compliance period. Allowances must be consigned to auction for the benefit of ratepayers, deposited for compliance, or a combination of both. Utilities may use allowances for compliance equal to their covered emissions in any calendar year they were not subject to potential penalty under CETA through 2045.

CETA also requires utilities to provide an equitable transition to cleaner energy through consideration of the energy and non-energy impact of resource decisions. The Department is participating in the rulemaking activities relating to CETA implementation by the Washington State Department of Commerce and will be evaluating compliance strategies for CETA requirements in the near future. The City has a wholesale power fuel mix that is approximately 90% carbon free, and will have no coal generated resources in its fuel mix after 2025, and is well positioned to meet 2030 carbon neutral requirements. Over the next several years, the City expects to develop strategies to meet the 2045 goal.

ELECTRIC UTILITY FINANCIAL INFORMATION

Historical Revenue and Expenses – Electric Utility

Table 10 shows audited historical revenues, expenses and changes in fund net assets for the Electric Utility for the years 2018-2021 and unaudited results for 2022. Table 11 provides 2023 budget information.

Table 9.
Historical Statement of Revenues, Expenses and Changes in Fund Net Position (1)

	2018	2019	2020	2021	2022(2)
Operating Revenue					
Charges for services (3)	$66,980,595	$72,881,112	$71,535,587	$74,589,326	$77,637,856
Other operating revenues	2,081,551	2,131,104	2,004,894	1,793,744	2,040,287
Total Operating Revenues	$69,062,146	$75,012,216	$73,540,481	$76,383,070	$79,678,143
Operation and Maintenance Expenses					
Maintenance and operations	$47,609,379	$49,018,101	$46,920,141	$45,876,603	48,293,044
Administrative and general	5,044,082	5,448,635	5,789,600	3,767,453	4,960,421
Taxes	7,910,222	8,491,948	8,348,663	8,946,719	9,317,027
Depreciation	6,330,879	5,878,747	6,114,666	6,358,130	6,575,440
Total operating expenses	$66,894,562	$68,837,431	$67,173,070	$64,948,905	$69,145,932
Net Operating Income	**$ 2,167,584**	**$ 6,174,785**	**$ 6,367,411**	**$11,434,165**	**$10,532,211**
Non-Operating Revenue/(Expenses)					
Investment Earnings	$ 372,508	$ 580,935	$ 205,738	$ (97,140)	$ (628,959)
Interest Expense	(2,610,562)	(2,870,471)	(2,810,057)	(2,683,446)	(2,726,700)
Debt costs	(432,470)	(243,218)	-	(179,888)	-
Miscellaneous Non-Operating Revenues/(Expenses)	1,337,125	292,400	112,306	(60,717)	(225,738)
Total Non-Operating Revenues/(Expenses)	$ (1,333,399)	$(2,240,314)	$ (2,492,013)	$ (3,021,191)	$ (3,581,397)
Net Income Before Contributions and Transfers	**$ (834,185)**	**$ 3,934,471**	**$ 3,855,398**	**$ 8,412,974**	**$ 6,950,814**
Capital contributions	$ 1,315,044	$ 1,149,766	$ 1,199,067	$ 1,161,550	$ 1,003,371
Transfers in (4)	11,000	-	-	-	-
Transfers out	(30,000)	(30,000)	(30,000)	(30,000)	(30,000)
Change in net position	$ 2,130,229	$ 5,054,237	$ 5,044,465	$ 9,544,524	$ 7,924,185
Net position-beginning	$ 50,158,486(6)	$52,288,715	$57,502,561	$62,547,026	$72,091,550
Prior period adjustments (5)	-	159,609	-	-	-
Net Position-Ending	**$52,288,715**	**$57,502,561**	**$62,547,026**	**$72,091,550**	**$80,015,735**

(1) Information is based on audited financial statements of the City.
(2) Unaudited.
(3) The City attributes changes in charges for services from year to year are to weather variability, along with an 8% rate increase in June 2019 and increased remote working during the COVID pandemic.
(4) Transfers in represent interdepartmental transfers to support projects that benefit multiple departments.
(5) Prior period adjustments were made in 2017 for prior year's Investment Cost Recovery Public Utility Tax Credits that were not claimed until 2017 and in 2019 to adjust accumulated depreciation on four assets found to be over depreciated when converting data to the City's new ERP system.
(6) As restated to reflect revised pension and OPEB accounting standards. See the captions "THE CITY—Pension Plans" and "THE CITY—Other Post-Employment Benefits."

Source: City of Richland

Table 10.
Electric Utility
Adopted 2023 Budgeted Revenues and Expenses

	Budgeted 2023
Operating Revenue	
Charges for services	$ 75,037,880
Other operating revenues	2,062,704
Total Operating Revenues	**$ 77,100,584**
Operation and Maintenance Expenses	
Maintenance and operations	$ 51,668,485[(1)]
Administrative and general	7,712,515
Taxes	9,121,618
Depreciation	6,700,000
Total Operating Expenses	**$ 75,002,618**
Net Operating Income	**$ 2,097,966**
Non-Operating Revenue/(Expenses)	
Investment earnings	$ 300,000
Interest Expense	(2,899,319)
Debt costs	(200,000)
Miscellaneous non-operating revenues/(expenses)	855,521
Total Non-Operating Revenues/(Expenses)	**$ (1,943,798)**
Net Income Before Contributions and Transfers	
Capital contributions	$ 650,000
Transfers out	(30,000)
Total	**$ 774,168**

(1) Adopted budget does not reflect $6,098,522 reserve distribution clause credit from Bonneville Power Administration. The final record of decision for the credit was communicated after the budget was adopted.

Source: City of Richland, adopted 2023 Budget for the Electric Utility.

Management Discussion of 2022 Year Unaudited Results

Activities in 2022 increased the Electric Utility's ending net position by approximately $8.4 million or 11.6% above the previous year-end balance. Annual debt repayment of $3.3 million and depreciation of $6.6 million were offset by the Electric Utility's $13.8 million investment in capital in 2022. In response to forecasted growth in customer and consumption base, $9.3 million in capital outlays was for projects that constructed, renewed and extended existing distribution infrastructure, as well as improved and expanded substation infrastructure. Capital outlay for equipment, machinery and software totaled over $4.5 million.

Operating revenue increased in 2022 by $3.3 million or 4.3% due to inconsistencies in customer loads and weather patterns. The last system-wide rate increase went into effect on June 1, 2019 and due to Bonneville rate adjustments, there is no additional rate action planned by the Electric Utility until 2024.

Operating expenses increased in 2022 by $3.7 million or 5.8% over the prior year. With weather factors impacting customer load in 2022, wholesale power cost increased $2.1 million. Additionally, the pension cost credit was $600,00 compared to the 2021 credit of $2.0 million. The credit is the result of State retirement plan investment earnings creating a pension asset at the system level. In previous years, the State plans typically carried plan liabilities. Richland, in tandem with other regional utilities, is constantly evaluating alternatives for its future wholesale power supply. The Electric Utility is currently in the 4th year of purchasing non-Federal power resources for new base power load and along with the base power load provide by Bonneville, the short-term purchased power outlook is stable. Operating expenses in total are continually being mitigated by cost containment measures taken during the budget development process.

System-wide energy consumption increased 2.9% and total customer accounts increased 1.2% in 2022. When looking at energy consumption changes by customer class, residential consumption increased by 8.1%, commercial consumption decreased by 1.4% and industrial consumption increased 4.5%. The irrigation and lighting class decreased by 14.1%. Trends of increasing commercial loads from economic development activity and decreasing residential energy consumption because of the City's energy conservation program investment are expected. Energy consumption is largely dependent on weather conditions, particularly for residential and commercial customers. The 2022 weather was typical for the area with extended summer periods with highs over 100 and winter low temperatures getting into single digits. June's weather spiked with a coincidental peak system demand set at 204MW. The heating degree day for November 2022 was 25% colder than the four-year average. Similarly, December 2022 was 18% colder than the four-year average. This resulted in higher customer consumption and higher wholesale power costs than typical for such months.

Supply chain issues caused higher material inventory costs associated with electrical distribution transformers and primary cable throughout 2022. Distribution transformer costs have increased five to six times costs before 2021 and primary distribution cable continues to be two times higher than before 2021. The Electric Utility has approximately $6.2 million of distribution transformer inventory and approximately $2.6 million of distribution cable inventory on order. Receipt of this inventory over 2023 and into 2024 will decrease general purpose cash.

The Electric Utility realized approximately $272,000 in total as credits to its wholesale power costs beginning December 2021 through September 2022. The credit was part of a Reserve Distribution Clause credit automatically triggered when Bonneville's financial reserves increased from higher energy prices on secondary sales to the wholesale market.

An Advanced Metering Infrastructure ("AMI") project began implementation in first quarter 2022, with delays in receiving meter materials causing the installation to continue into 2023. The AMI project is expected to be completed by the end of 2023.

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Historical Debt Service Coverage Calculations

The following table shows the calculation of Net Revenue available for debt service and debt service coverage for the Electric Utility for the past five years. The debt service coverage calculations set forth below are intended to reflect compliance with the rate covenant contained in the relevant ordinances authorizing the Bonds and outstanding Parity Bonds and for no other purpose. Such calculations may reflect non-recurring or extraordinary transactions permitted under the bond ordinances and generally accepted accounting principles.

Table 11.
Historical Net Revenue and Debt Service Coverage for the Electric Utility(1)

	2018	2019	2020	2021	2022(2)
Operating Revenues					
Retail Power Sales Revenue (3)	$ 61,290,914	$ 66,690,130	$ 65,459,120	$ 68,255,563	$ 71,044,868
Other Electric Operating Revenue	2,081,550	2,131,104	2,004,894	1,793,744	2,040,287
Total Operating Revenues	$ 63,372,464	$ 68,821,234	$ 67,464,014	$70,049,307	$ 73,085,155
Operating Expenses					
Maintenance and Operations (4)	$ 47,344,154	$ 48,726,353	$ 46,599,089	$ 45,123,589	$ 47,904,727
Administrative and General	5,044,082	5,448,636	5,789,601	3,767,453	4,960,421
Taxes (Excluding City Occupation Tax)	2,216,871	2,297,053	2,268,138	2,606,626	2,717,809
Total Operating Expenses	$ 54,605,107	$ 56,472,042	$ 54,656,828	$ 51,497,668	$ 55,582,957
Net Income from Operations	$ 8,767,357	$ 12,349,192	$ 12,807,186	$ 18,551,639	$ 17,502,198
Non-Operating Revenues/(Expenses)					
Miscellaneous Non-Operating Revenues/(Expenses)	$ 1,149,963	$ 108,473	$ 111,358	$ (60,717)	$ (225,738)
Interest Income (5)	386,260	433,934	265,409	84,904	336,507
Capital Contributions (6)	889,979	769,098	608,853	928,305	473,058
Total Non-Operating Revenues/(Expenses)	$ 2,426,202	$ 1,311,505	$ 985,620	$ 952,492	$ 583,827
Net Revenue Available for Parity Bond Debt Service	**$ 11,193,559**	**$ 13,660,697**	**$ 13,792,806**	**$ 19,504,131**	**$ 18,086,025**
Aggregate Parity Bond Debt Service (7)	**$ 6,093,870**	**$ 5,766,790**	**$ 6,004,366**	**$ 6,056,269**	**$ 6,281,582**
Debt Service Coverage Ratio	**1.84x**	**2.37x**	**2.30x**	**3.22x**	**2.88x**

(1) The debt service coverage ratios provided above have been calculated in accordance with the definition of "Coverage Requirement" provided in the applicable parity bond authorizing ordinances for the Parity Bonds outstanding in the applicable year. Such calculations are derived from the definitions of Gross Revenue, Maintenance and Operation Expense, Net Revenue and Adjusted Net Revenue, and Annual Debt Service. Certain of these definitions have been amended during the time periods shown, due to springing covenants set forth in the applicable ordinances. For the definitions provided in the Bond Ordinance, see APPENDIX A – THE BOND ORDINANCE – Article 1.
(2) Unaudited.
(3) Excludes City Utility Tax collections. See "THE ELECTRIC UTILITY—Utility Taxes" above.
(4) Excludes Operating Transfer to the Equipment Replacement Fund.
(5) Excludes Gains and Losses on Fair Market Value adjustments.
(6) Excludes non-cash Capital Contributions.
(7) In 2018, the definition of Annual Debt Service was adjusted to permit the exclusion of debt service expected to be paid from the receipt of Tax Credit Subsidy Bond Payments in respect of the City's Electric Revenue Bonds, 2009 (Taxable Build America Bonds-Direct Payment) (the "2009 Bonds"). This adjustment is reflected in the above calculations beginning in 2018. Tax Credit Subsidy Bond Payments are no longer shown as revenues under the line item "Miscellaneous Non-Operating Revenues" beginning in 2018. The 2009 Bonds were refunded in 2019 and the City does not currently receive Tax Credit Subsidy Bond Payments.

Source: City of Richland

THE CITY

The City was incorporated in 1958 as a first-class charter city and operates under the Council-Manager form of government. A seven-member Council is the legislative body of the City and establishes and controls policy for the City. Council members are elected to staggered terms by the qualified electors of the City, as follows. Council elections are held every two years. At each Council election four positions are elected. The three candidates receiving the highest number of votes are elected to serve 4-year terms, and the candidate receiving the fourth highest number of votes is elected to a two-year term. The City Council elects one of its members to serve as Mayor for a two-year term.

The City Council appoints a City Manager, who is the Chief Executive Officer and hires personnel, supervises daily operations and oversees enforcement of laws and preparation of the annual budget.

The City Council holds regular meetings twice each month, workshop sessions once each month, and special meetings as needed. All meetings are open to the public as provided by law and agenda items are prepared in advance.

The following are the Mayor and members of the City Council.

Elected Official	Position	Current Term Expires
Terry Christensen	Mayor	December 31, 2023
Theresa Richardson	Mayor Pro Tem	December 31, 2023
Jhoanna Jones	Council Member	December 31, 2023
Sandra Kent	Council Member	December 31, 2025
Ryan Lukson	Council Member	December 31, 2025
Shayne VanDyke	Council Member	December 31, 2023
Ryan Whitten	Council Member	December 31, 2023

Brief resumes of key City staff follow:

Jon Amundson, City Manager. On December 7, 2021, the City Council appointed Jon Amundson as City Manager. As City Manager, he oversees ten departments and an employee base of over 500. Jon came to the City of Richland in 2008 as Assistant City Manager. Jon received his Bachelor of Arts in American Studies from Brigham Young University, Masters in Public Administration from the University of Kansas, and completed the Senior Executive Institute in the Weldon Cooper Center for Public Service at the University of Virginia Darden School of Business. In 2016, Jon became an International City/County Management Association (ICMA) Credentialed Manager. Jon is also a certified Project Management Professional.

Drew Florence, Assistant City Manager. Mr. Florence was appointed to the position of Assistant City Manager in September 2021. He holds a Master of Public Administration from American Public University and a Bachelor of Arts in Police Science from Ottawa University. Since 2012, Mr. Florence has been an employee of the Richland Police Department, most recently as a Police Captain. Mr. Florence began his public service career with the Town of Gilbert (Arizona), in 2005. In the role of Administrative Services Director, he oversees Finance, Customer Service, Purchasing, Warehouse, and Fleet divisions.

Brandon Allen, Finance Director. Mr. Allen joined the City in 2014. Prior to joining the City, Mr. Allen was the Controller for Trios Health, a Public Hospital District. Mr. Allen has a Bachelor of Business Administration in business and accounting from Utah Valley University, and an MBA from the University of Utah. Mr. Allen is also a Certified Public Accountant (CPA).

City Funds and Accounting

Each year the City prepares an Annual Comprehensive Financial Report to communicate the results of the City's operations. The government-wide financial statements are reported using the economic resources measurement focus and the accrual basis of accounting, as are the proprietary and fiduciary fund financial statements (with the exception of agency funds which have no measurement focus). Revenues are recorded when earned and expenses are recorded when a liability is incurred, regardless of the timing of related cash flows. Grants and similar items are recognized as revenue as soon as all eligibility requirements imposed by the provider have been met.

Governmental fund financial statements are reported using the current financial resources measurement focus and the modified accrual basis of accounting. Revenues are recognized as soon as they are both measurable and available. Revenues are considered to be available when they are collectible within the current period or soon enough thereafter to pay liabilities of the current period. For this purpose, the City considers revenues to be available if they are collected within 60 days of the end of the current fiscal period. Property taxes and the portion of special assessments receivable due within the current fiscal period are considered to be susceptible to accrual and so have been recognized as revenues of the current fiscal period. All other revenue items are considered to be measurable and available only when cash is received by the City. Expenditures generally are recorded when a liability is incurred as under accrual accounting.

However, debt service expenditures, as well as expenditures related to compensated absences and claims and judgments, are recorded only when payment is due. Because of the differences in measurement focus and basis of accounting between the governmental funds and government-wide financial statements, reconciliations are provided to facilitate the understanding of the City's financial statements. The governmental funds balance sheet includes a detailed reconciliation between fund balances of all governmental funds and governmental activities net assets as reported in the government-wide statement of net assets. The governmental fund statement of revenues, expenditures and changes in fund balances includes a detailed reconciliation between the net changes in fund balances for all governmental funds and the changes in governmental activities net assets as reported in the government-wide statement of activities.

Auditing

Accounting systems and budgetary controls are prescribed by the Office of the State Auditor in accordance with State law. The City complies with the systems and controls prescribed by the Office of the State Auditor and establishes procedures and records which reasonably assure safeguarding of assets and the reliability of financial reporting.

The State Auditor is required to examine the affairs of cities regularly and on a schedule determined by risk factors and financial activity. The City has been subject to annual financial statement and accountability audits. Financial statement audits are performed for the purpose of forming an opinion on the financial statements taken as a whole. Also considered are the City's internal controls over financial reporting and tests of compliance with certain provisions of laws, regulations, contracts and grant agreements and other matters. Accountability audits include, among other things, review of the financial condition and resources of the City, whether the laws and constitution of the State are being complied with, the methods and accuracy of the accounts and reports as well as other matters (potential areas of risk related to citizen concerns, payroll, inter-fund transactions). Reports of the auditor's examinations are filed in the office of the State Auditor and in the Finance Department of the City.

The 2021 audited financial statements are included as APPENDIX C herein.

Budgetary Process

Annual appropriated budgets are adopted by ordinance in accordance with State law for all funds except agency funds. While not required by law, the City also adopts budgets for proprietary funds and debt service funds. These budgets are appropriated at the fund level. The budget constitutes the legal authority for expenditures at that level. Annual appropriations for these funds lapse at the Fiscal Year end. Appropriations for other purpose funds that are non-operating in nature are adopted on a "project-length" basis, and therefore, are carried forward from year to year without re-appropriations until authorized amounts are fully expended or the designated purpose of the fund has been accomplished. Annual appropriated budgets are adopted on the same basis of accounting used for financial reporting. The City Council is required to hold public hearings prior to budget adoption.

The City Manager prepares a preliminary budget, which is required by State law to be filed with the City Clerk by November 1. This budget is based on strategic goals established by the City Manager and the City Council and estimates provided by City department directors during the preceding months, and balanced with revenue estimates and existing fund balance, when necessary. The City Council is then required to set public hearings and make copies of the preliminary budget available to citizens. The City Council must adopt a final budget no later than December 31. The Finance Director is authorized to transfer budgeted amounts between departments within any fund and object classes within departments, and if necessary, the City Council may amend the budget at any time. Any revisions that alter the total expenditures of a fund or that affect the number of authorized employee positions, salary ranges, hours, or other conditions of employment must be approved by the City Council.

Authorized Investments and City Investment Policy

Authorized Investments. Chapter 35.39 RCW limits the investment of funds of local governments to the following authorized instruments: (i) bonds of the State or any local government in the State; (ii) general obligation bonds of any other state or local government thereof which have at the time of investment one of the three highest credit ratings of a nationally recognized rating agency; (iii) registered warrants of a local government in the same county as the local government making the investment; (iv) obligations of the U.S. government, its agencies and wholly owned corporations, or obligations issued or guaranteed by supranational institutions, provided, that at the time of investment, the United States government is the largest shareholder of such institution; (v) obligations of the Federal Home Loan Bank, Federal Land Bank and Fannie Mae, and obligations of other government-sponsored corporations whose obligations are or may become eligible as collateral for advances to member banks of the Federal Reserve System,

(vi) bankers' acceptances purchased on the secondary market; (vii) commercial paper purchased on the secondary market, subject to State Investment Board policies; and (viii) corporate notes purchased on the secondary market, subject to State Investment Board policies.

Money available for investment may be invested on an individual fund basis or may, unless otherwise restricted by law, be commingled within one common investment portfolio. All income derived from such investment may be either apportioned to and used by the various participating funds or for the benefit of the general government in accordance with city ordinances or resolutions. Funds derived from the sale of bonds or other instruments of indebtedness will be reinvested or used in such manner as the authorizing ordinances, resolutions, or bond covenants may lawfully prescribe.

Local Government Investment Pool. The State Treasurer's Office administers the Local Government Investment Pool (the "LGIP"), an approximately $19 billion dollar fund (as of March 31, 2023) that invests money on behalf of more than 600 local governments. In its management of LGIP, the State Treasurer is required to adhere, at all times, to the principles appropriate for the prudent investment of public finds. These are, in priority order, (i) the safety of principal; (ii) the assurance of sufficient liquidity to meet cash flow demands; and (iii) to attain the highest possible yield within the constraints of the first two goals. Historically, the LGIP has had sufficient liquidity to meet all cash flow demands.

The LGIP, authorized by chapter 43.250 RCW, is a voluntary pool which provides its participants the opportunity to benefit from the economies of scale inherent in pooling. It is also intended to offer participants increased safety of principal and the ability to achieve a higher investment yield than would otherwise be available to them. Although not regulated by the U.S. Securities and Exchange Commission (the "SEC"), the LGIP is invested in a manner generally consistent with the SEC guidelines for Rule 2a-7 money market funds; for example, currently it has a maximum weighted average maturity of 60 days and a maximum weighted average life of 120 days. The maximum final maturity is 397 days except for floating and variable-rate securities and securities that are used for repurchase agreements. The weighted average maturity of the LGIP generally ranges from 30 to 60 days. Investments permitted under the pool's guidelines include U.S. government and agency securities, bankers' acceptances, high quality commercial paper, repurchase and reverse repurchase agreements, motor vehicle fund warrants, and certificates of deposit issued by qualified State depositories. The City may withdraw funds in their entirety on less than 24-hours' notice.

Authorized Investments for Bond Proceeds. In addition to the eligible investments discussed above, bond proceeds may also be invested in mutual funds with portfolios consisting of U.S. government and guaranteed agency securities with average maturities of less than four years; municipal securities rated in one of the four highest categories; and money market funds consisting of the same, so long as municipal securities held in the fund(s) are in one of the two highest rating categories of a nationally recognized rating agency. Bond proceeds may also be invested in shares of money market funds with portfolios of securities otherwise authorized by law for investment by local governments (RCW 39.59.030).

The following table shows cash and investments as of July 31, 2022 and December 31, 2022.

Table 12.
City Cash and Investments

	Amount as of July 31, 2022	Amount as of December 31, 2022
Banks and Savings and Loan Institutions	$ 2,628,516	$ 5,810,656
LGIP Investments	45,035,033	40,350,472
Non-Pool Investments [(1)]	150,650,376	148,451,334
Total Cash and Investments	$ 198,313,925	$ 194,612,462

(1) Includes U.S. Treasury and U.S. Agency securities, bank notes and municipal bonds.
Source: City of Richland

Employees and Bargaining Groups

The budgeted number of full-time equivalent ("FTE") City employees for the years 2019 through 2023 is listed below.

Table 13.
Budgeted City Employees

Year	FTEs
2019	530
2020	542
2021	547
2022	559
2023	580

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Source: City of Richland

Certain City employees are represented by one of six bargaining groups, and the City enters into written bargaining agreements with each bargaining organization. The City negotiates labor contracts through a management team with support from a consultant. The following provides information on unions and bargaining groups representing City employees as of March 31, 2023. The City considers its relations with all employees and bargaining units to be good. The City is currently in negotiations with the bargaining groups whose contracts expired in December 2021 and the parties will continue to operate under the terms of the expired contracts until new contracts are entered into.

Table 14.
City Bargaining Units

Union or Bargaining Group	Primary Type of Employee Represented	Number of FTEs	Contract Expires
International Brotherhood of Electrical Workers, Local Union No. 77, AFL-CIO ("IBEW")	Electricians	27	12/31/2023
International Union of Operating Engineers, Local Union No. 280 ("IUOE")	Various	99	12/31/2024
Teamsters	Dispatchers	32	12/19/2021(1)
Richland Police Guild	Police Officers	53	12/31/2025
IAFF, Local Union No. 1052	Firefighters	59	12/31/2021(1)
BC Battalion Chief's Bargaining Unit, Local No. 1052	Battalion Chiefs	5	12/31/2021(1)
Police Command Staff	Commanders/Lieutenants	4	N/A (2)
Total		279	

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(1) These contracts are under negotiation. The parties are continuing to operate under the terms of the expired contract until negotiations are completed.
(2) This is a new Bargaining Group and the contract is currently under negotiation.
Source: City of Richland

Pension Plans

Introduction. Substantially all City full-time and qualifying part-time employees are eligible for participation in one of the following statewide cost-sharing multiple-employer plans administered by the State's Department of Retirement Systems ("DRS"): Public Employees Retirement System ("PERS") Plans 1, 2 and 3; and the Law Enforcement Officers and Fire Fighters Retirement System ("LEOFF") Plans 1 and 2. The State Legislature establishes, and from time to time amends, laws pertaining to the creation and administration of these public retirement systems; however, employees are contractually entitled to receive plan benefits.

The information in this section has been obtained from the City's financial statements and information on the websites of DRS and of the Office of the State Actuary (the "State Actuary"), a nonpartisan legislative agency charged with advising the Legislature and Governor on pension benefits and funding policy. DRS issues a publicly available Annual Comprehensive Financial Report that includes financial statements and required supplementary information for each plan. The DRS Annual Comprehensive Financial Report ("DRS ACFR") may be obtained from the DRS website at www.drs.wa.gov.

In addition to the State sponsored pension plans that the City participates in, the City also administers two local single employer defined benefit pension plans for pre-LEOFF fire and police retirees. LEOFF Plan 1 participants who joined prior to and were active on March 1, 1970 are entitled to the greater of the benefits under LEOFF Plan 1 or under the prior Police Relief Pension Fund or the Fire Relief Pension Fund maintained by the City. These two local plans are described below under "— *City Administered Police and Firefighters' Relief and Pension Plans.*"

State Sponsored Plan Descriptions. All PERS and LEOFF plans provide retirement, disability and death benefits. Plans 1 and 2 (both PERS and LEOFF) are defined benefit plans. PERS Plan 3 is a hybrid defined benefit/defined contribution plan. Contributions by both employees and employers are based on gross wages. PERS and LEOFF participants who joined the system by September 30, 1977 are Plan 1 members. Those PERS participants who joined on or after October 1, 1977, are Plan 2 members, unless they exercise an option to transfer to Plan 3. PERS participants joining on or after September 1, 2002, have the irrevocable option of choosing membership in PERS Plan 2 or PERS Plan 3*. LEOFF participants who joined on or after October 1, 1977, are Plan 2 members.

Benefits provided by each plan are based on a percentage of the member's average final compensation ("AFC"), multiplied by years of service. The percentages and methods for calculating AFC vary among the plans, as do vesting and retirement eligibility (age and years of service) requirements. Additional detail about each Plan is available in the DRS ACFR and in Note 10 to the City's annual financial statements, attached as APPENDIX C.

Plan Funding Status and Unfunded Actuarial Liability. All DRS-administered retirement plans are funded by a combination of funding sources: (i) contributions from the State; (ii) contributions from employers (including the State as employer and the City and other governmental employers); (iii) contributions from employees; and (iv) investment returns. The retirement funds (the "Commingled Trust Fund" or "CTF") are invested by the Washington State Investment Board ("WSIB"), a 15-member board created by the State Legislature in 1981. For the quarter ended December 31, 2022, WSIB reported the annualized one-, three-, five-, and 10-year rates of return as -3.18%, 9.93%, 9.30%, and 9.71%, respectively. The annualized rate of return for the quarter ended December 31, 2022 was 3.61%.

PERS Plans 2 and 3 are accounted for in the same pension trust fund and may legally be used to pay the defined benefits of any PERS Plan 2 or 3 participant. Assets for other plans may not be used to fund benefits for another plan; however, all employers in PERS Plan 2 and 3 are required to make contributions at rates (percentage of payroll) determined by the State Actuary every two years for the purpose of amortizing within a rolling 10-year period the unfunded actuarial accrued liability in PERS Plan 1.

The most recently completed actuarial report was released in August 2022 for the Fiscal Year ended June 30, 2021. According to that report, the funded ratio for most plans remained between 90% and 104%, except for PERS Plan 1 and TRS Plan 1 (measuring 71% and 73%, respectively) and LEOFF Plan 1 (measuring 146%). The total funded ratio across all plans for the year ended June 30, 2021 decreased to 93%, compared to 95% as of June 30, 2020.

Table 16.
DRS-Administered Pension Plan Funded Status(1)
(Dollars in millions)

Plan		Actuarial Accrued Liability	Actuarial Value of Assets	Unfunded Actuarial Accrued Liability/(Surplus)	Plan Funded Ratio
PERS	Plan 1	$ 11,368	$ 8,064	$ 3,303	71%
	Plans 2/3	52,039	49,451	2,588	95%
LEOFF	Plan 1	4,209	6,143	(1,934)	146%
	Plan 2	15,819	16,494	(676)	104%

(1) As of June 30, 2021, the most recent actuarial valuation date. Liabilities valued using the Entry Age Normal cost method at an interest rate of 7.0% (7.4% for LEOFF 2). All assets valued using the Actuarial Value of Assets method.

Source: 2021 Actuarial Valuation

GASB 67/68 Reporting of Liability Information. The Governmental Accounting Standard Board ("GASB") Statement 68, Accounting and Financial Reporting for Pensions ("GASB 68") became effective for the City for the year ended December 31, 2015. In accordance with GASB 68, lower discount rates are required to be used for underfunded plans in certain cases and the difference between expected and actual investment returns each year will be recognized over a closed five-year smoothing period. GASB 68 also requires employers that participate in the

* Effective July 28, 2019, as a result of Senate Bill 5360 passed in 2019, new plan members default into Plan 2 unless they elect into Plan 3.

State-sponsored plans to report their proportionate share of Net Pension Liability, Deferred Inflows of Resources, Deferred Outflows of Resources, and Pension Expense for the State plans. DRS determines each participating employer's proportionate share of overall plan liability and the State Actuary determines each plan's accounting valuation. GASB 68 affects the accounting for pensions, but does not change the funding status of the plans calculated by State Actuary or pension contribution rates that are set based on statutory assumptions.

As of December 31, 2022, the City reported $5.5 million for its proportionate share of total pension liability related to PERS Plan 1 and $9.6 million for its share of net pension assets related to PERS Plans 2 and 3. Approximately 19.5% of the City's share was attributable to the Electric Utility. The City also reported a total pension asset of $15.7 million for its share of net pension assets related to Law Enforcement Officers and Firefighters (LEOFF) Plans 1 & 2. LEOFF plan assets are not eligible to offset liabilities of the PERS plans.

Table 17.
Schedule of City's Proportionate Share of Net Pension Liability(1)

	PERS 1	PERS 2/3	LEOFF 1	LEOFF 2
Proportionate Share of NPL (%)(2)	0.198149%	0.258001%	0.126497%	0.444254%
City's Share of Net Liability (Asset)	$ 5,517,195	$ (9,568,692)	$ (3,628,409)	$ (12,073,482)
City's Share of Pension Expense	2,794,081	(3,321,490)	(231,060)	(1,950,365)

(1) As of June 30, 2022.
(2) Represents City's proportionate share of State-administered plan.
Source: City of Richland, Annual Comprehensive Financial Report, 2022

Table 18.
City of Richland – Aggregate Pension Amounts – All Plans

City Share of :	2021	2022
Total Pension Liabilities (TPL)	$ (6,983,853)	$ (8,619,074)
Total Pension Assets	51,708,090	25,270,883
Deferred Outflows of Resources	5,080,785	16,290,807
Deferred Inflows of Resources	(39,030,920)	(17,064,991)
Pension Expense/Expenditures	(19,548,451)	(74,914)

Source: City of Richland, Annual Comprehensive Financial Reports, 2021 and 2022

Contribution Rates and Amounts. Under State statute, contribution rates are adopted by the Pension Funding Council ("PFC") and, for LEOFF Plan 2, by the LEOFF Plan 2 Retirement Board (the "LEOFF 2 Board"), in even-numbered years for the next ensuing State biennium, which runs for a two year period beginning on July 1 and ending on June 30. The rate-setting process begins with an actuarial valuation by the State Actuary, who makes non-binding recommendations to the Select Committee on Pension Policy, which then recommends contribution rates to the PFC and the LEOFF 2 Board. No later than the end of July in even-numbered years, the PFC and LEOFF 2 Board adopt contribution rates, which are subject to revision by the Legislature.

The City's total contribution for the year ended December 31, 2022, was $4,116,581, which was made up of $3,186,021 to PERS and $817,869 to LEOFF 2. (LEOFF 1 is fully funded and there was no required employer or employee contribution (other than the administrative cost) for 2022). The City's total contribution for the year ended December 31, 2021, was $4,352,220, which was made up of $3,498,759 to PERS and $853,461 to LEOFF 2.

The following table outlines the contribution rates of employees and employers set for the 2019-21 State fiscal biennium and the 2021-23 State fiscal biennium (Fiscal Years ending June 30). Any unfunded pension benefit obligations within the systems could be reflected in future years as higher contribution rates.

Table 19.
Employer and Employee Pension Contribution Rates[1]

		2021-23 State Fiscal Biennium (effective July 1, 2021 through June 30, 2023)		PFC Adopted Rates for 2023-25 Biennium (subject to change by Legislature)	
		Employee	**Employer[2]**	**Employee**	**Employer[2]**
PERS	Plan 1	6.00%[3]	12.25%	6.00%[3]	10.43%
	Plan 2	6.36%	12.25%	6.36%	10.43%
	Plan 3	Variable[4]	12.25%	Variable[4]	10.43%
LEOFF	Plan 1	0.00%	0.18%	0.00%	0.18%
	Plan 2	8.53%	8.71%[5]	8.53%	8.71%[5]

(1) Rates are set by State fiscal biennia, reflecting Fiscal Years ending June 30; all rate changes are effective July 1.
(2) Includes 0.18% DRS administrative expense rate.
(3) Rate statutorily set at 6.0%.
(4) Rates vary from 5.0% minimum to 15.0% maximum based on rate selected by the PERS 3 member.
(5) Includes a contribution by the State of approximately 40% of the LEOFF Plan 2 employer contribution rate. The City pays the remaining employer contribution, plus the 0.18% DRS administrative fee.

Source: Washington State Department of Retirement Systems

The State Legislature has established certain minimum contribution rates that became effective in 2015 and remain in effect until the actuarial value of assets in PERS Plan 1 equals one hundred percent of the actuarial accrued liability of PERS Plan 1. These rates are subject to change by future legislation enacted by the State Legislature to address future changes in actuarial and economic assumptions and investment performance.

Actuarial Valuation Methods and Assumptions. State law requires systematic actuarial funding to finance the ongoing cost of the state retirement systems. Actuarial calculations to determine employer and employee contributions are prepared by the State Actuary. To calculate employer and employee contribution rates necessary to prefund the plans' benefits, the State Actuary uses actuarial cost and asset valuation methods selected by the Legislature as well as economic and demographic assumptions.

The State Actuary uses the Entry Age Normal ("EAN") cost method to report each plan's funded status. The annual cost of benefits under EAN is comprised of two components: normal cost plus amortization of the unfunded liability. The normal cost is most commonly determined on an individual basis, from a member's age at plan entry, and is designed to be a level percentage of pay throughout a member's career. Comparing the EAN liabilities to the actuarial value of assets ("AVA") on the valuation date provides an appropriate measure of a plan's funded status and is acceptable according to current GASB Statements 67 and 68. For purposes of determining the actuarial accrued liability of each plan and certain benefits provided under each plan, the State Actuary uses actuarial cost and asset valuation methods determined by the Legislature, which requirements differ from plan to plan. For purposes of calculating contribution rates the Legislature determines the long-term assumed rate of investment return to be used by the State Actuary, which was 7.0% for all plans.

The actuarial assumptions used in the 2021 Actuarial Valuation were based on the results of the State Actuary's 2013-2018 Demographic Experience Study and the 2021 Economic Experience Study. The actuarial valuation to be prepared in calendar year 2023 will be based on assumptions and changes in law that are recommended and adopted by the PFC, including assumption adjustments reflecting the Economic Experience Study and the Demographic Experience Study that are expected to be finalized in fall 2023.

City Administered Police and Firefighters' Relief and Pension Plans. The City administers two single employer defined benefit pension and retiree healthcare plans for certain law enforcement officers ("Police Pension") and firefighters ("Fire Pension") who entered service prior to March 1, 1970. Members of these plans are entitled to the greater of the benefits provided under either the Police Pension or Fire Pension plan (as applicable) or LEOFF Plan 1, and the City is responsible for the cost of the excess of the pension benefit over the LEOFF benefit.

These plans are the predecessors to the LEOFF retirement plans described above and are closed to new entrants. The City has no active employees in these plans; all plan members are retirees. As of December 31, 2022, there were 13 retirees or beneficiaries receiving benefits under the Fire Pension plan and 14 retirees or beneficiaries receiving benefits under the Police Pension plan.

The Police Pension and the Fire Pension (collectively, the "City Plans") are managed by separate boards, each consisting of the Mayor or Mayor Pro-Tem, the City Clerk, the City Finance Director and representatives of plan beneficiaries. The City Plans are required to be funded on a pay-as-you-go basis such that funds are available to make benefit payments due in each year. The City Plans are not governed by investment policies, and their investments consist primarily of long held mutual funds, cash, and short-term interfund loans to other City funds.

Contributions to the Fire Pension are derived from two sources: (1) an annual property tax levy that is capped by State law at $0.225 per $1,000 of assessed value, and (2) certain revenues transferred by the State from fire insurance premium taxes. The City annually appropriates its contributions to the Police Pension out of revenues received from the issuance of licenses and from fines and forfeitures collected or received in money for violation of City ordinances.

Additional information about the Police Pension and Fire Pension plans is available in the City's annual financial statements, Note 10, which was prepared in accordance with GASB 68. See APPENDIX C—2021 Audited Financial Statement.

Other Post-Employment Benefits

In addition to pensions, many State and local governmental employers provide other post-employment benefits ("OPEB") as a part of total compensation to attract and retain the services of qualified employees. OPEB includes post-employment health care as well as other forms of post-employment benefits when provided separately from a pension plan. The Governmental Accounting Standards Board ("GASB") standard concerning Accounting and Financial Reporting by Employers for Post-Employment Benefits Other than Pensions ("GASB 75") provides for the measurement, recognition and display of OPEB expenses/expenditures, related liabilities (assets), note disclosures, and, if applicable, required supplementary information in the financial reports.

The City's OPEB plans consist of a post-employment health care plan open to all eligible City retirees who have not opted out of the plan, and two separate plans for LEOFF Plan 1 fire and LEOFF Plan 1 police retirees. The Citywide OPEB plan is closed to entrants as of December 31, 2012.

The City's funding policy is based upon pay-as-you-go financing requirements, with the City paying benefits as they come due. Actuarial assumptions for Fiscal Year 2022 include the following: inflation: 5.00%; salary increases: 3.50%; investment rate of return (discount rate): 4.05%; healthcare cost trend rate: 7.40%.

The following table shows the changes in the City's net OPEB obligation during the City's Fiscal Year ended December 31, 2022:

Table 20.
Changes in Other Post-Employment Benefits Liability
(Fiscal Year Ended 12/31/2022)

Plan	Citywide	LEOFF 1 (Fire)	LEOFF 1 (Police)
Balance as of 12/31/21	$ 9,009,017	$ 3,920,705	$ 4,727,042
Changes for the year			
Service cost	$ 342,624	-	-
Interest	165,051	71,148	85,802
Changes of benefit terms	-	-	-
Differences between expected and actual experience	(2,500,483)	(1,227,706)	(726,784)
Changes of assumptions	(725,932)	(566,291)	(800,485)
Contributions	-	-	-
Net investment income	-	-	-
Benefit payments	(360,887)	(107,982)	(127,862)
Implicit rate subsidy fulfilled	(402,080)	-	-
Administrative expenses	-	-	-
Net Changes	$ (3,481,707)	$ (1,830,831)	$ (1,569,329)
Balance as of 12/31/2022	**$ 5,527,310**	**$ 2,089,874**	**$ 3,157,713**

Source: City of Richland

The City's annual OPEB cost, the percentage of annual OPEB cost contributed to the plan, and the net OPEB obligation for the Police and Fire LEOFF 1 plans for Fiscal Years ending December 31, 2018 through 2022 were as follows:

Table 21.
Historical Summary of Other Post-Employment Benefits

Fiscal Year Ended	Annual OPEB Cost	Employer Contribution	Contribution as a % of Annual OPEB Cost	Net OPEB Obligation
2018	$ 879,231	$ 1,088,198	123.77%	$ 10,859,388
2019	840,099	1,325,383	157.77%	10,047,417
2020	673,272	880,074	130.72%	9,317,685
2021	540,630	761,924	140.93%	4,009,017
2022	11,663	762,967	6,541.77%	5,527,310

Source: City of Richland

Risk Management

The City is a member of the Washington Cities Insurance Authority ("WCIA"). Utilizing chapter 48.62 RCW (self-insurance regulation) and chapter 39.34 RCW (Interlocal Cooperation Act), nine cities originally formed WCIA on January 1, 1981. WCIA was created for the purpose of providing a pooling mechanism for jointly purchasing insurance, jointly self-insuring, and/or jointly contracting for risk management services. WCIA has 166 members.

New members initially contract for a three-year term, and thereafter automatically renew on an annual basis. A one-year withdrawal notice is required before membership can be terminated. Termination does not relieve a former member from its unresolved loss history incurred during membership.

Liability coverage is written on an occurrence basis, without deductibles. Coverage includes general, automobile, police, errors or omissions, stop gap, employment practices and employee benefits liability. Limits are $4 million per occurrence self-insured layer, and $16 million in limits above the self-insured layer is provided by reinsurance. Total limits are $20 million per occurrence subject to aggregates and sublimits. The Board of Directors determines the limits and terms of coverage annually.

All members are provided a separate cyber risk policy and premises pollution liability coverage group purchased by WCIA. The cyber risk policy provides coverage and separate limits for security & privacy, event management, and cyber extortion, with limits up to $1 million and subject to member deductibles, sublimits, and a $5 million pool aggregate. Premises pollution liability provides members with a $2 million incident limit and $10 million pool aggregate subject to a $100,000 per incident member deductible.

Insurance coverage for property, automobile physical damage, fidelity, inland marine, and boiler and machinery are purchased on a group basis. Various deductibles apply by type of coverage. Property coverage is self-funded from the members' deductible to $750,000, for all perils other than flood and earthquake, and insured above that to $400 million per occurrence subject to aggregates and sublimits. Automobile physical damage coverage is self-funded from the members' deductible to $250,000 and insured above that to $100 million per occurrence subject to aggregates and sublimits.

In-house services include risk management consultation, loss control field services, claims and litigation administration. WCIA contracts for certain claims investigations, consultants for personnel issues and land use issues, insurance brokerage, actuarial and lobbyist services.

WCIA is fully funded by its members, who make annual assessments on a prospectively rated basis, as determined by an outside, independent actuary. The assessment covers loss, loss adjustment, reinsurance and other administrative expenses. As outlined in the interlocal agreement, WCIA retains the right to additionally assess the membership for any funding shortfall.

An investment committee, using investment brokers, produces additional revenue by investment of WCIA's assets in financial instruments which comply with all State guidelines.

A board of directors governs WCIA, which is comprised of one designated representative from each member. The board elects an executive committee and appoints a treasurer to provide general policy direction for the organization. The WCIA executive director reports to the executive committee and is responsible for conducting the day to day operations of WCIA.

The City of Richland paid $1,931,576 in premiums for coverage in 2022.

GENERAL AND ECONOMIC INFORMATION

General

The City is located in Benton County, in the southeastern portion of the State, approximately 220 miles southeast of Seattle and 150 miles southwest of Spokane. The City and the cities of Kennewick, in the County, and Pasco in neighboring Franklin County make up the urban area known as the Tri-Cities.

Population

The City's population ranks 21st in overall population in the State. Historical and current population figures for the City and the County as of April 1 of each year are provided below.

Table 22.
Population Estimates
(as of April 1)

Year	City of Richland	Benton County
2013	51,150	183,400
2014	52,090	186,500
2015	52,090	188,590
2016	53,080	190,500
2017	54,150	193,500
2018	55,320	197,420
2019	56,850	201,800
2020(1)	58,550	205,700
2021	59,570	209,300
2022	62,220	212,300

(1) 2020 U.S. Census numbers.

Source: Washington State Office of Financial Management; U.S. Census Bureau

Economic Development

The City is adjacent to the site of the Hanford Nuclear Reservation ("Hanford"). Hanford, located on the Columbia River just north of the City, sits on 586 square miles and is one of the largest nuclear industrial centers in the United States. Since its establishment in 1943, U.S. Department of Defense activity on this site has attracted a highly-educated workforce employed in energy and technology sectors. Today, there are various nuclear-related projects located on site, operated by multiple public agencies and private entities, including ongoing energy and environmental research as well as the efforts to clean up the site from its historical role in nuclear weapons production.

Energy Sector Research and Technology. The largest employer in the City is the Pacific Northwest National Laboratory ("PNNL"), operated by Battelle Memorial Institute ("Battelle"). The City has been home to PNNL since 1965. PNNL employs over 5,700 people with a diverse research portfolio including smart grid and energy storage technologies and other worldwide energy, national security, and environmental research.

Approximately 5% of PNNL's research is Hanford-related environmental research related to cleanup of the Hanford nuclear site. According to the U.S. Environmental Protection Agency, Hanford is now the most contaminated Superfund site in the U.S. and constitutes one of the nation's largest environmental cleanup projects. A number of other industries supporting this cleanup effort are also present in the City.

PNNL and Washington State University (Tri-Cities) are anchor tenants of the Tri-Cities Research District located in north Richland. A private development group has recently made an investment estimated at approximately $50 million to create the Innovation Center, a private research campus located between PNNL and WSU-Tri-Cities.

Outside of the cleanup mission, the U.S. Department of Energy leases some Hanford land to the State, which in turn leases it out for two independent operations: Washington State Department of Ecology, for commercial low-level radioactive waste burial, and Energy Northwest utility consortium for its Columbia Generating Station.

In April 2021, the U.S. Department of Energy awarded $80M in grant funding towards the X-Energy advanced nuclear reactor partnership with Energy Northwest and Grant Public Utility District. Energy Northwest is headquartered in

Richland and operates the regions commercial nuclear power generation facility. X-Energy is being considered for siting at an existing Energy Northwest location approved for nuclear generation.

Framatome operates a nuclear fuel fabrication facility in Richland that is used in reactors across the US to generate 5% of all electricity in the US.

Agriculture and Viticulture. Agriculture and agri-business are major contributors to the local area economy, with farmland comprising the majority of land in the County. The City hosts several industries supportive of agriculture, including a major industrial freezer operation, industrial food research facilities and two major industrial food processors, Conagra Brands, Inc. and Lamb Weston Holdings, Inc., which recently completed a major expansion estimated at over $200 million. Preferred Freezer began construction of a $35 million expansion of its facility that was completed July 2019. Packaging Corp of America began operation of its new manufacturing facility in 2020.

The region is also known for producing wine, with more than 160 wineries within 60 miles of the City and a Viticulture and Enology program offered by WSU Tri-Cities. This industry attracts tourism to the many wine tasting venues.

Transportation. The area also provides widely accessible barge, rail, trucking and air transportation. The eight dams along the Columbia and Snake rivers make it possible for ocean barges to travel from the Pacific Ocean to the Tri-Cities, and as far east as Idaho. Burlington Northern-Santa Fe and Union Pacific railroads serve the area's rail transportation needs. The Tri-Cities Airport in Pasco currently has a number of daily flights offered by six commercial airlines to ten destinations throughout the western United States.

Major Economic Indicators for the City and the County

The following tables present historical information on certain major economic indicators for the City, the County, the State and the Tri-Cities area.

Table 23.
City of Richland Major Employers
(as of March 31, 2023)

Employer	Type of Business	Approximate Number of Employees
Battelle Memorial Institute	Research and Development	5,300
Kadlec Regional Medical Center	Health Services	3,800
Washington River Protection Solutions LLC	Environmental Remediation Services	2,336
Richland School District	K-12 Education	2,200
Central Plateau Cleanup Company LLC	Environmental Remediation Services	2,100
Bechtel National, Inc.	Engineering and Consultation	2,000
Hanford Mission Integration Solutions, LLC	Environmental Remediation Services	1,912
Energy Northwest	Power Generation Facility	1,000
Lamb Weston, Inc.	Food Processing	970
Waste Treatment Completion Company LLC	Environmental Remediation Services	649

Source: City of Richland

Table 24.
Civilian Labor Force and Employment
(Not Seasonally Adjusted)

	Annual Average					
	2018	**2019**	**2020**	**2021**	**2022[(1)]**	**Feb. 2023[(2)]**
City of Richland						
Civilian Labor Force	28,850	30,200	30,990	30,732	31,470	32,063
Employment	27,449	28,773	28,671	29,180	29,958	30,079
Unemployment	1,401	1,427	2,319	1,552	1,512	1,682
Unemployment Rate	4.9%	4.7%	7.5%	5.1%	4.8%	6.2%
Benton County						
Civilian Labor Force	99,575	104,153	105,564	104,773	107,625	109,501
Employment	94,389	98,586	97,191	98,915	101,552	101,963
Unemployment	5,186	5,567	8,373	5,858	6,073	7,538
Unemployment Rate	5.2%	5.3%	7.9%	5.6%	5.6%	6.9%
Washington State						
Civilian Labor Force	3,814,538	3,933,880	3,936,084	3,898,707	3,990,343	4,092,579
Employment	3,645,992	3,766,964	3,603,370	3,695,705	3,822,319	3,887,545
Unemployment	168,546	166,916	332,714	203,002	168,024	205,034
Unemployment Rate	4.4%	4.2%	8.5%	5.2%	4.2%	5.0%

(1) Annual averages not available at the City or County level for 2022. Preliminary numbers for December, 2022 are shown here. State numbers are annual average.
(2) Preliminary.
Source: Bureau of Labor Statistics (revised as of March 1, 2023).

Table 25.
Nonagricultural Wage and Salary Employment
(Kennewick-Pasco-Richland MSA, Not Seasonally Adjusted) ($ thousands)

NAICS INDUSTRY	2018	2019	2020	2021	2022	2023[(1)]
Total Nonfarm	115.4	118.3	113.1	117.4	123.1	124.2
Total Private	95.5	99.2	94.8	99.1	104.2	104.7
Goods Producing	17.5	18.7	18.4	18.7	19.7	19.7
Mining, Lodging and Construction	9.3	10.3	10.3	10.6	10.8	10.3
Manufacturing	8.2	8.4	8.1	8.1	8.9	9.4
Services Providing	97.9	99.6	94.7	98.7	103.4	104.6
Private Service Providing	78.0	80.4	76.4	80.4	84.5	85.0
Trade, Transportation, and Utilities	19.7	19.7	19.4	20.7	21.7	21.4
Retail Trade	13.4	13.3	13.0	14.0	14.4	14.1
Financial Activities	4.1	4.2	4.0	4.1	4.3	4.3
Professional and Business Services	21.2	21.8	21.1	21.6	22.2	22.5
Administrative and Support Services	11.4	11.7	11.3	11.9	12.3	12.3
Educational and Health Services	16.8	18.2	18.1	18.8	19.5	20.0
Leisure and Hospitality	11.8	12.1	9.6	11.1	12.5	12.6
Food Services	8.9	9.0	7.7	8.8	9.8	9.8
Government	19.9	19.2	18.3	18.3	18.9	19.6
Workers in Labor/Management Disputes	0.0	0.0	0.0	0.0	0.0	0.0

(1) Average through February, 2023.
Source: Washington State Employment Security Department

Table 26.
Per Capita Personal Income

Year	Kennewick-Richland MSA	Benton County	State of Washington	United States
2017	42,363	45,375	57,265	51,550
2018	42,974	45,920	60,221	53,786
2019	44,599	48,522	64,189	56,250
2020	48,979	51,895	68,350	59,763
2021	52,082	54,958	73,775	64,117
2022	(1)	(1)	75,698	65,423

(1) 2022 data not yet available for these areas.
Source: U.S. Department of Commerce Bureau of Economic Analysis (March 31, 2023)

Table 27.
Taxable Retail Sales for the City of Richland

Year	City of Richland
2018	1,329,523,203
2019	1,522,409,959
2020	1,479,476,283
2021	1,791,272,907
2022(1)	1,405,977,133

(1) Through third quarter only. For comparison, taxable retail sales through third quarter 2021 were $1,315,875,734.
Source: Department of Revenue

LEGAL AND TAX INFORMATION

No Litigation Relating to the Bonds

There is no litigation pending or threatened questioning the validity of the Bonds or the power and authority of the City to issue the Bonds. There is no litigation pending or threatened which would materially affect the City's ability to meet debt service requirements on the Bonds. Because of the nature of its activities, the City is subject to certain pending legal actions which arise in the ordinary course of business. Based on the information presently known, the City believes that the ultimate liability for any of such legal actions will not be material to the financial position of the City.

Approval of Counsel

Legal matters incident to the authorization, issuance, and sale of the Bonds by the City are subject to the approving legal opinion of Stradling Yocca Carlson & Rauth, a Professional Corporation, Bond Counsel, Seattle, Washington. The form of the opinion of Bond Counsel is attached as Appendix B. The opinion of Bond Counsel is given based on factual representations made to Bond Counsel, and under existing law, as of the date of initial delivery of the Bonds, and Bond Counsel assumes no obligation to revise or supplement its opinion to reflect any facts or circumstances that may thereafter come to its attention, or any changes in law that may thereafter occur. The opinion of Bond Counsel is an expression of its professional judgment on the matters expressly addressed in its opinion and does not constitute a guarantee of result. Bond Counsel will be compensated only upon the issuance and sale of the Bonds.

Tax Matters

In the opinion of Stradling Yocca Carlson & Rauth, a Professional Corporation, Seattle, Washington, Bond Counsel, under existing statutes, regulations, rulings and judicial decisions, and assuming the accuracy of certain representations and compliance with certain covenants and requirements described herein, interest on the Bonds is excluded from gross income for federal income tax purposes and is not an item of tax preference for purposes of calculating the federal alternative minimum tax imposed on individuals. However, it should be noted that for tax years beginning after December 31, 2022, with respect to applicable corporations as defined in Section 59(k) of the Internal Revenue Code of 1986, as amended (the "Code"), generally certain corporations with more than $1,000,000,000 of average annual adjusted financial statement income, interest on the Bonds might be taken into account in determining adjusted financial statement income for purposes of computing the alternative minimum tax imposed by Section 55 of the Code on such corporations.

Bond Counsel's opinion as to the exclusion from gross income for federal income tax purposes of interest on the Bonds is based upon certain representations of fact and certifications made by the City and others and is subject to the condition that the City complies with all requirements of the Code that must be satisfied subsequent to the issuance of the Bonds to assure that interest on the Bonds will not become includable in gross income for federal income tax purposes. Failure to comply with such requirements of the Code might cause the interest on the Bonds to be included in gross income for federal income tax purposes retroactive to the date of issuance of the Bonds. The City will covenant to comply with all such requirements.

The amount by which a Beneficial Owner's original basis for determining loss on sale or exchange in the applicable Bond (generally, the purchase price) exceeds the amount payable on maturity (or on an earlier call date) constitutes amortizable bond premium, which must be amortized under Section 171 of the Code; such amortizable bond premium reduces the Beneficial Owner's basis in the applicable Bond (and the amount of tax-exempt interest received), and is not deductible for federal income tax purposes. The basis reduction as a result of the amortization of bond premium may result in a Beneficial Owner realizing a taxable gain when a Bond is sold by the Beneficial Owner for an amount equal to or less (under certain circumstances) than the original cost of the Bond to the Beneficial Owner. Purchasers of the Bonds should consult their own tax advisors as to the treatment, computation and collateral consequences of amortizable bond premium.

The Internal Revenue Service (the "IRS") has initiated an expanded program for the auditing of tax-exempt bond issues, including both random and targeted audits. It is possible that the Bonds will be selected for audit by the IRS. It is also possible that the market value of the Bonds might be affected as a result of such an audit of the Bonds (or by an audit of similar bonds). No assurance can be given that in the course of an audit, as a result of an audit, or otherwise, Congress or the IRS might not change the Code (or interpretation thereof) subsequent to the issuance of the Bonds to the extent that it adversely affects the exclusion from gross income of interest on the Bonds or their market value.

SUBSEQUENT TO THE ISSUANCE OF THE BONDS THERE MIGHT BE FEDERAL, STATE, OR LOCAL STATUTORY CHANGES (OR JUDICIAL OR REGULATORY CHANGES TO OR INTERPRETATIONS OF FEDERAL, STATE, OR LOCAL LAW) THAT AFFECT THE FEDERAL, STATE, OR LOCAL TAX TREATMENT OF THE BONDS INCLUDING THE IMPOSITION OF ADDITIONAL FEDERAL INCOME OR STATE TAXES ON OWNERS OF TAX-EXEMPT STATE OR LOCAL OBLIGATIONS, SUCH AS THE BONDS. THESE CHANGES COULD ADVERSELY AFFECT THE MARKET VALUE OR LIQUIDITY OF THE BONDS. NO ASSURANCE CAN BE GIVEN THAT SUBSEQUENT TO THE ISSUANCE OF THE BONDS STATUTORY CHANGES WILL NOT BE INTRODUCED OR ENACTED OR JUDICIAL OR REGULATORY INTERPRETATIONS WILL NOT OCCUR HAVING THE EFFECTS DESCRIBED ABOVE. BEFORE PURCHASING ANY OF THE BONDS, ALL POTENTIAL PURCHASERS SHOULD CONSULT THEIR TAX ADVISORS REGARDING POSSIBLE STATUTORY CHANGES OR JUDICIAL OR REGULATORY CHANGES OR INTERPRETATIONS, AND THEIR COLLATERAL TAX CONSEQUENCES RELATING TO THE BONDS.

Bond Counsel's opinions may be affected by actions taken (or not taken) or events occurring (or not occurring) after the date hereof. Bond Counsel has not undertaken to determine, or to inform any person, whether any such actions or events are taken or do occur. The Bond Ordinance and the Tax Certificate relating to the Bonds permit certain actions to be taken or to be omitted if a favorable opinion of a bond counsel is provided with respect thereto. Bond Counsel expresses no opinion as to the effect on the exclusion from gross income for federal income tax purposes of interest on any Bond if any such action is taken or omitted based upon the advice of counsel other than Bond Counsel.

Although Bond Counsel will render an opinion that interest on the Bonds is excluded from gross income for federal income tax purposes provided that the City continues to comply with certain requirements of the Code, the ownership of the Bonds and the accrual or receipt of interest with respect to the Bonds may otherwise affect the tax liability of certain persons. Bond Counsel expresses no opinion regarding any such tax consequences. Accordingly, before purchasing any of the Bonds, all potential purchasers should consult their tax advisors with respect to collateral tax consequences relating to the Bonds.

CONTINUING DISCLOSURE

Undertaking to Provide Annual Financial Information and Notice of Listed Events. To meet the requirements of paragraph (b)(5) of United States Securities and Exchange Commission (the "SEC") Rule 15c2-12 (the "Rule 15c2-12"), as applicable to a participating underwriter for the Bonds, the City has entered into a Continuing Disclosure Agreement, and will undertake for the benefit of holders of the Bonds to provide or cause to be provided, either directly or through a designated agent, to the Municipal Securities Rulemaking Board (the "MSRB"), in an electronic format as prescribed by the MSRB accompanied by identifying information as prescribed by the MSRB:

(i) Annual financial information and operating data of the type included in this Official Statement as generally described below ("annual financial information"). If audited financial statements are unavailable, the timely filing of unaudited financial statements shall satisfy the requirements and filing deadlines set forth in subsection (b), and the City agrees to file audited financial statements if and when they are otherwise prepared and available to the City.

(ii) Timely notice (not in excess of ten business days after the occurrence of the event) of the occurrence of any of the following events with respect to the Bonds: (a) principal and interest payment delinquencies; (b) non-payment related defaults, if material; (c) unscheduled draws on debt service reserves reflecting financial difficulties; (d) unscheduled draws on credit enhancements reflecting financial difficulties; (e) substitution of credit or liquidity providers, or their failure to perform; (f) adverse tax opinions, the issuance by the IRS of proposed final determinations of taxability, Notice of Proposed Issue (IRS Form 5701 – TEB) or the material notices or determinations with respect to the tax status of the Bonds, or other material events affecting the tax status of the Bonds; (g) modifications to rights of holders of the Bonds, if material; (h) Bond calls (other than scheduled mandatory redemptions of Term Bonds), if material, and tender offers; (i) defeasances; (j) release, substitution, or sale of property securing repayment of the Bonds, if material; (k) rating changes; (l) bankruptcy, insolvency, receivership or similar event of the City, as such "Bankruptcy Events" are defined in Rule 15c2-12; (m) the consummation of a merger, consolidation, or acquisition involving the City or the sale of all or substantially all of the assets of the City, other than in the ordinary course of business, the entry into a definitive agreement to undertake such an action or the termination of a definitive agreement relating to any such actions, other than pursuant to its terms, if material; (n) appointment of a successor or additional trustee or the change of name of a trustee, if material; (o) default, event of acceleration, termination event, modification of terms or other similar events under the terms of a Financial Obligation (as such term is defined below) of the City, any of which reflect financial difficulties; and (p) incurrence of a Financial Obligation of the City or agreement to covenants, events of default, remedies, priority rights or other similar terms of a Financial Obligation of the City, any of which affect security holders.

"Financial Obligation" means: (a) a debt obligation; (b) a derivative instrument entered into in connection with, or pledged as security or a source of payment for, an existing or planned debt obligation; or (c) guarantee of (a) or (b). The term "Financial Obligation" does not include municipal securities as to which a final official statement has been provided to the MSRB consistent with Rule 15c2-12 and the issuer thereof has entered into a continuing disclosure undertaking for such municipal securities.

The City also will provide to the MSRB timely notice of a failure by the City to provide required annual financial information on or before the date specified below.

Annual Financial Information to be Provided. The annual financial information that the City undertakes to provide will consist of:

(1) Annual financial statements prepared (except as noted in the financial statements) in accordance with applicable generally accepted accounting principles applicable to local governmental units of the State such as the City, as such principles may be changed from time to time, which statements may be unaudited, provided, that if and when audited financial statements are prepared and available they will be provided;

(2) A statement of outstanding Parity Bonds of the Electric Utility at year-end;

(3) Debt service coverage ratios for the Outstanding Parity Bonds at year-end;

(4) Number of Electric Utility customers; and

(5) Ten largest Electric Utility customers.

The Annual Financial Information shall be provided not later than the last day of the ninth month after the end of each Fiscal Year of the City (currently, a Fiscal Year ending December 31), as such Fiscal Year may be changed as required or permitted by State law, commencing with the City's Fiscal Year ending December 31, 2023.

The Annual Financial Information may be provided in a single or multiple documents, and may be incorporated by specific reference to documents available to the public on the Internet website of the MSRB or filed with the SEC.

Amendment of Continuing Disclosure Agreement. The Continuing Disclosure Agreement is subject to amendment after the primary offering of the Bonds without the consent of any Owner or holder of any Bond, or of any broker, dealer, municipal securities dealer, participating underwriter, rating agency or the MSRB, under the circumstances and in the manner permitted by Rule 15c2-12, including: (i) the amendment may only be made in connection with a change in circumstances that arises from a change in legal requirements, change in law, or change in the identity, nature, or status of the City, or type of business conducted; (ii) the undertaking, as amended, would have complied with the requirements of Rule 15c2-12 at the time of the primary offering, after taking into account any amendments or interpretations of Rule 15c2-12, as well as any change in circumstances; and (iii) the amendment does not materially impair the interests of holders, as determined either by parties unaffiliated with the City (e.g., bond counsel or other counsel familiar with federal securities laws), or by approving vote of bondholders pursuant to the terms of the Bond Ordinance at the time of the amendment.

Termination of Continuing Disclosure Agreement. The City's obligations under the Continuing Disclosure Agreement will terminate upon the legal defeasance of all of the Bonds. In addition, the City's obligations under the Continuing Disclosure Agreement will terminate if those provisions of Rule 15c2-12 which require the City to comply with the Continuing Disclosure Agreement become legally inapplicable in respect of the Bonds for any reason, as confirmed by an opinion of nationally recognized bond counsel or other counsel familiar with federal securities laws delivered to the City, and the City provides timely notice of such termination to the MSRB.

Remedy for Failure to Comply with Continuing Disclosure Agreement. If the City or any other obligated person fails to comply with the Continuing Disclosure Agreement, the City will proceed with due diligence to cause such noncompliance to be corrected as soon as practicable after the City learns of that failure. No failure by the City or other obligated person to comply with the Continuing Disclosure Agreement will constitute a default in respect of the Bonds. The sole remedy of any holder of a Bond will be to take such actions as that holder deems necessary, including seeking an order of specific performance from an appropriate court, to compel the City or other obligated person to comply with the Continuing Disclosure Agreement.

Compliance with Prior Continuing Disclosure Obligations. The City has entered into certain written agreements for the sole purpose of assisting an underwriter in meeting the requirements of paragraph (b)(5) of Rule 15c2-12, as applicable to a participating underwriter for certain of its outstanding bonds (the "Prior Undertakings"). The City's review of its compliance during the past five years did not reveal any failure to comply, in a material respect, with any Prior Undertakings in effect during this time. Within the last five years, the City has made filings to correct failures to file certain annual financial information that occurred more than five years ago.

CERTAIN INVESTMENT CONSIDERATIONS

The purchase of the Bonds involves investment risk. Prospective purchasers of the Bonds should consider carefully all of the information set forth in this Official Statement, including its appendices, evaluate the investment considerations and merits of an investment in the Bonds and confer with their own tax and financial advisors when considering a purchase of the Bonds.

The Bonds are payable from and secured solely by the Net Revenue of the Electric Utility. The City's ability to derive Net Revenue from the ownership and operation of the Electric Utility sufficient to pay debt service on the Bonds (and Outstanding Parity Bonds and Future Parity Bonds) depends on many factors, some of which are not subject to the control of the City. The following section discusses some of the factors affecting Net Revenue and the Electric Utility. The following discussion cannot, however, describe all of the factors that could affect Net Revenue and the Electric Utility. In addition to these known factors, other factors could affect Net Revenue and the Electric Utility. The order in which the following information is presented is not intended to reflect the relative importance of any such risks.

Seismic Risk, Nuclear and Other Hazardous Materials Risk, and Other Considerations.

Regional Emergency Management and Preparedness. Benton County Emergency Management ("BCEM") is responsible for managing and coordinating resources and coordinating resources and responsibilities across Benton and Franklin Counties. BCEM prepares for emergencies, trains local government staff in emergency response, provides education to the community about emergency preparedness, plans for emergency recovery, and works to mitigate known hazards. It has identified and assessed many types of hazards that may have an impact countywide, including geophysical hazards (e.g., earthquakes, landslides, seismic events, and volcanic eruptions), infectious disease outbreaks, intentional hazards (e.g., terrorism, breaches in cybersecurity, and civil disorder), transportation incidents, fires, hazardous materials, and unusual weather conditions (e.g., floods, snow, water shortages, and wind storms). Neither the City nor BCEM can anticipate all potential hazards and their effects, including any potential impact on the economy of the City or the region. BCEM has a federally approved Natural Hazard Mitigation Plan.

The City is adjacent to the Hanford Nuclear Reservation, which is home to one of the nation's largest Superfund sites and the Columbia Generating Station nuclear power plant, and houses several nuclear research facilities. This poses some inherent risks of radiological disasters. BCEM maintains disaster plans to prepare for emergencies at the Hanford Site, Energy Northwest's Columbia Generating Station (located on the Hanford site) and the nearby Umatilla Chemical Depot. In addition, the City joins with the nearby cities and counties as part of Hanford Communities to keep citizens apprised of activities related to Hanford cleanup activities, to coordinate local government involvement in U.S. Department of Energy decision-making and to interact with the U.S. Department of Energy, the Environmental Protection Agency and the Washington State Department of Ecology, among others.

BCEM has identified and assessed many types of hazards that may have an impact countywide, including geophysical hazards (e.g., earthquakes, landslides, seismic events, and volcanic eruptions) as well as other hazards: infectious disease outbreaks, intentional hazards (e.g., terrorism, breaches in cybersecurity, and civil disorder), transportation incidents, fires, hazardous materials (including nuclear), and unusual weather conditions (e.g., floods, snow, water shortages, and wind storms). In addition, the City is located adjacent to the Hanford Nuclear Reservation, which poses some inherent risks of radiological disasters. BCEM maintains disaster plans to prepare for emergencies at the Hanford Site, Energy Northwest's Columbia Generating Station (located on the Hanford site) and the nearby Umatilla Chemical Depot. See "GENERAL AND ECONOMIC INFORMATION — Regional Risk Management."

If a disaster were to damage or destroy a substantial portion of the taxable property within the City, the assessed value of such property could be reduced, which could result in a reduction of property tax revenues. It could also substantially damage utility infrastructure and utility revenues. Other revenue sources, such as sales tax and lodging tax, could also be reduced. In addition, substantial financial and operational resources of the City could be required during any emergency event or disaster and could be diverted to the subsequent repair of damage to City infrastructure.

The City can give no assurance regarding the effect of any hazard or that proceeds of insurance carried by the City would be sufficient, if available, to rebuild and reopen Electric Utility facilities or that the facilities or surrounding infrastructure could or would be rebuilt and reopened in a timely manner following a major earthquake or other natural disaster or hazard.

Global Health Emergency Risks and Covid-19 Pandemic

Pandemics and other widespread public health emergencies can and do arise from time to time and can affect broader economic conditions and the State's financial condition. The State cannot predict whether future pandemics and other public health emergencies may arise that could impact the economy generally or the City's financial condition. The Covid-19 pandemic that began in 2020 negatively affected local, State, national, and global economic activity. The Governor declared a state of emergency due to the Covid-19 pandemic in February 2020, which enabled the exercise of various public health and safety measures. The State emergency declaration ended as of October 31, 2022 and the federal public health emergency ended on May 11, 2023. The City cannot predict whether another such emergency could occur and could affect the City, its residents, or its financial condition.

Various Factors Affecting the Electric Utility Industry Generally

A number of factors could impact the results of operations of the Electric Utility, including a decrease in the number of or other change in customers, changes in regional and local economic conditions, changes in regulatory or permit requirements, changes in population, increase in Operation and Maintenance Expenses, and changes in general market conditions.

The electric utility industry in general has been, or in the future may be, affected by a number of factors which could impact the financial condition and competitiveness of many electric utilities and the level of utilization of generating and transmission facilities.

In addition to the factors discussed above under "POWER SUPPLY AND TRANSMISSION," such factors include, among others, (1) effects of compliance with rapidly changing environmental, safety, licensing, regulatory and legislative requirements; (2) changes resulting from conservation and demand-side management programs on the timing and use of electric energy; (3) changes in national energy policy; (4) effects of competition from other electric utilities (including increased competition resulting from mergers, acquisitions, and "strategic alliances" of competing electric and natural gas utilities and from competitors transmitting less expensive electricity from much greater distances over an interconnected system) and new methods of, and new facilities for, producing low-cost electricity; (5) the repeal of certain federal statutes that would have the effect of increasing the competitiveness of many investor-owned utilities; (6) increased competition from independent power producers and marketers, brokers, and federal power marketing agencies; (7) "self-generation" or "distributed generation" such as rooftop solar, microturbines and fuel cells; (8) effects of inflation on the operating and maintenance costs of the electric utility and its facilities; (9) changes from projected future load requirements; (10) increases in costs and uncertain availability of capital; (11) shifts in the availability and relative costs of different fuels (including the cost of natural gas); (12) increases or decreases in the price of energy purchased or sold on the open market that may occur in times of high peak demand; (13) issues with transmission capacity and integrating wind power and other renewable energy generation; (14) inadequate risk management procedures and practices with respect to, among other things, the purchase and sale of energy and transmission capacity; (15) other legislative changes, voter initiatives, referenda, statewide propositions, sequestration and other failures of Congress to act; (16) effects of the changes in the economy; (17) effects of possible manipulation of the electric markets; (18) natural disasters or other physical calamities including, but not limited to, earthquakes, tsunami, droughts, floods, wildfires, mudslides, volcanic eruptions, and windstorms; (19) man-made physical and operational disasters, including but not limited to terrorism, security (including cybersecurity) breaches, cyber-attacks, and collateral damage from untargeted computer viruses; (20) variations in the weather and changes in the climate; and (21) failures of or other issues with infrastructure. Any of these factors (as well as other factors not discussed here) could have an adverse effect on the financial condition of any given electric utility and likely will affect individual utilities in different ways.

The City is unable to predict what impact such factors will have on the Electric Utility, its business operations and financial condition. This Official Statement includes a brief discussion of some of these factors and does not purport to be comprehensive or definitive, and these matters are subject to change subsequent to the date hereof. Extensive information on the electric utility industry is available from the legislative and regulatory bodies and other sources in the public domain. Potential purchasers of the Bonds may wish to obtain and review such information.

Climate Change

There are potential risks to the City and the Electric Utility associated with changes to the climate over time and from increases in the frequency, timing, and severity of extreme weather events. The Electric Utility's resource mix is currently dependent on hydro-based generation, and climate change may affect the amount, timing, and availability of hydroelectric generation in the future. The Integrated Resource Planning process and Clean Energy Implementation Plan is expected to consider the effects of climate change on the resource mix available to the Electric Utility. See "POWER SUPPLY AND TRANSMISSION—Resource Planning—*Integrated Resource Planning and Renewable Portfolio Standards*." The City cannot predict how or when various climate change risks may occur, nor can it quantify the impact on the City, its population, or its operations. Over time, the costs could be significant and could have a material adverse effect on the City's finances by requiring greater expenditures to counteract the effects of climate change.

Cybersecurity and Physical Security

Cybersecurity threats continue to become more sophisticated and are increasingly capable of impacting the confidentiality, integrity, and availability of City systems and applications, including those of critical controls systems. The City has practices in place to address cybersecurity, as well as limited cybersecurity insurance coverage through the Washington Cities Insurance Authority (WCIA), which includes security audits and guidance and access to third-party cyber specialists in the event of a data breach incident. The City has engaged outside parties to provide risk assessment and will continue to do additional assessments in the future. In October 2021, City Council approved a contract award to a cybersecurity consulting firm to review City risks and develop a five year roadmap to further reduce cyber risks. The Electric Utility is not required to comply with the cybersecurity regulations of the North American Energy Reliability Corporation ("NERC") but considers NERC standards as guidance for best practices. Cybersecurity risks create potential liability for exposure of nonpublic information and could create various other operational risks. During first quarter 2023, the City completed a physical security assessment conducted by the Electricity Information Sharing and Analysis Center ("E-ISAC"), along with local and regional utility and law enforcement participants. The physical security assessment was part of an E-ISAC Vulnerability Infrastructure Security Assessment. Some of the recommendations from the physical security assessment are expected to be included in the 2024 budget development process. The City cannot anticipate the precise nature of any particular cybersecurity or physical security breach or the resulting consequences.

Federal Policy Risk and Other Federal Funding Considerations.

Federal Sequestration. The sequestration provisions of the Budget Control Act of 2011 ("Sequestration") have been in effect since 2013 and are currently scheduled to remain in effect through federal fiscal year ("FFY") 2029. This results in a slight reduction in the expected subsidy in respect of certain Build America Bonds previously issued by the City. The City does not expect Sequestration to materially adversely affect its ability to make debt service payments in the current or future years.

Federal Grant Funding Conditions. The City receives federal financial assistance for specific purposes that are generally subject to review or audit by the grantor agencies. Entitlement to this assistance is generally conditioned upon compliance with the terms of grant agreements and applicable federal regulations, including the expenditure of assistance for allowable purposes. Any disallowance resulting from a review or audit may become a liability of the City.

Federal Shutdown Risk. Federal government shutdowns have occurred in the past and could occur in the future. A lengthy federal government shutdown poses potential direct risks to the City's receipt of revenues from federal sources and could have indirect impacts due to the shutdown's effect on general economic conditions. The City has not experienced material adverse impacts from the federal government shutdowns that have occurred in the past but can make no assurances that it would not be materially adversely affected by any future federal shutdown.

Initiative and Referendum

State Initiative and Referendum. Under the State Constitution, the voters of the State have the ability to initiate legislation and require the State Legislature to refer legislation to the voters through the power of initiative and referendum, respectively. The initiative power in the State may not be used to amend the State Constitution. Initiatives and referenda are submitted to the voters upon receipt of petitions signed by at least eight percent (initiatives) and four percent (referenda) of the number of voters registered and voting for the office of Governor at the preceding regular gubernatorial election. Any law approved in this manner by a majority of the voters may not be amended or repealed by the State Legislature within a period of two years following enactment, except by a vote of two–thirds of all the members elected to each house of the State Legislature. After two years, the law is subject to amendment or repeal by the State Legislature in the same manner as other laws.

In recent years, initiatives and referenda have been filed in the State that affect the powers of local jurisdictions. The City cannot predict whether such measures will be filed in the future, whether any filed initiatives will receive the requisite signatures to be certified to the ballot, and whether such initiatives will be approved by the voters and, if challenged, upheld by the courts.

Local Initiative and Referendum. The City charter provides for local initiatives and referenda. Initiatives and referenda are submitted to the voters upon receipt of petitions signed by at least 20 percent (initiatives) and 25% (referenda) of the total vote cast at the last preceding regular general election. Referendum petitions must be filed within 30 days after first publication of the ordinance that is the subject of the referendum. The referendum period for the Bond Ordinance expires on May 23, 2023. An initiative ordinance or an ordinance repealed as a result of a referendum petition may not be amended (initiative) or reenacted (referendum) by the City Council for one year. Neither the initiative nor referendum may be used to amend the City charter and may not address any subject that is barred under State law, including administrative or ministerial actions; ordinances necessary for immediate preservation of public peace, health, and safety or for the support of City government and its existing public institutions which contain a statement of urgency and are passed by unanimous vote of the City Council; ordinances providing for local improvement districts; ordinances appropriating money; ordinances providing for or approving collective bargaining; ordinances providing for the compensation of or working conditions of City employees; and ordinances authorizing or repealing the levy of taxes. From time to time voters may submit petitions for initiatives and referenda within the City. The City cannot predict when or if any such measures would be filed, or what the subject or effect of any such potential measure may be.

Limitations on Remedies; Bankruptcy

Any remedies available to the owners of the Bonds upon the occurrence of an event of default under the Bond Ordinance are in many respects dependent upon judicial actions, which are in turn often subject to discretion and delay and could be both expensive and time consuming to obtain. If the City fails to comply with its covenants under the Bond Ordinance or to pay principal of or interest on the Bonds, there can be no assurance that available remedies will be adequate to fully protect the interests of the owners of the Bonds.

In addition to the limitations on remedies contained in State law, the rights and obligations under the Bonds and the Bond Ordinance may be limited by and are subject to bankruptcy, insolvency, reorganization, fraudulent conveyance, moratorium, and other laws relating to or affecting creditors' rights, to the application of equitable principles, and to the exercise of judicial discretion in appropriate cases.

The legal opinion of Bond Counsel regarding the validity of the Bonds will be qualified by reference to bankruptcy, reorganization, insolvency, fraudulent conveyance, moratorium and other similar laws affecting the rights of creditors generally, and by general principles of equity.

A municipality such as the City must be specifically authorized under state law in order to seek relief under Chapter 9 of the U.S. Bankruptcy Code (the "Bankruptcy Code"). Chapter 39.64 RCW, entitled the "Taxing District Relief Act," permits any "taxing district" (defined to include any municipality or political subdivision, including cities) to voluntarily petition for relief under the Bankruptcy Code. A creditor cannot bring an involuntary bankruptcy proceeding against a municipality, including the City. Under Chapter 9, a federal bankruptcy court may not appoint a receiver for a municipality or order the dissolution or liquidation of the municipality. The federal bankruptcy courts have some discretionary powers under the Bankruptcy Code.

Should the City become a debtor in a federal bankruptcy proceeding, the owners of the Bonds would continue to have a statutory lien on Net Revenue after the commencement of the bankruptcy case so long as the Net Revenue constitute "special revenues" within the meaning of the Bankruptcy Code. "Special revenues" are defined under the Bankruptcy Code to include, among other things, receipts by local governments from the ownership, operation or disposition of projects or systems that are primarily used to provide utility services. The Bankruptcy Code provides that "special revenues" can be applied to necessary operating expenses of the project or system, before they are applied to other obligations. This rule applies regardless of the provisions of the transaction documents, such as the Bond Ordinance. It is not clear precisely which expenses would constitute necessary operating expenses and any definition in the Bond Ordinance may not be applicable. If Net Revenue do not constitute "special revenues," there could be delays or reductions in payments by the City with respect to the Bonds.

Changes in State and Federal Laws and Regulation

The City and the Electric Utility are subject to federal, State, and local laws and regulations. These statutory and regulatory requirements are subject to change and could become more stringent and costly for the City, the Electric Utility or its customers. For example, statutory or regulatory requirements addressing water quality, mitigating flood concerns, limiting emissions, addressing climate change or otherwise affecting the Electric Utility could be implemented or increased. The City cannot predict whether future restrictions or limitations on the Electric Utility will be imposed, whether future legislation or regulations will affect operations, Operation and Maintenance Expenses, funding for capital projects or whether such restrictions or legislation or regulations will adversely affect Net Revenue.

No Acceleration

The Bond Ordinance provides that the remedy of acceleration is not available to the owners of the Parity Bonds under any circumstances, including upon the occurrence and continuance of an event of default. The City is liable for principal and interest payments only as they became due, and the Registered Owner would be required to seek a separate judgment for each payment, if any, not made. Any such action for monetary damages would be subject to any limitations on legal claims and remedies against public bodies under State law. Amounts recovered would be applied to unpaid installments of interest prior to being applied to unpaid principal and premium, if any, which had become due. See "SECURITY AND SOURCES OF PAYMENT."

Federal Tax Law Changes After Issue Date May Affect Marketability of Bonds

From time to time, there are legislative proposals in Congress and IRS rulemaking activities which could adversely affect the market value or marketability of the Bonds. It cannot be predicted whether future legislation, rules, regulations or other guidance may be proposed or enacted that would affect the federal tax treatment of interest received on the Bonds. Prospective purchasers of the Bonds should consult with their own tax advisors regarding any pending or proposed legislation or regulations that would change the federal tax treatment of interest on the Bonds.

BOND INSURANCE

Bond Insurance Policy

Concurrently with the issuance of the Bonds, Build America Mutual Assurance Company ("BAM") will issue its Municipal Bond Insurance Policy for the Bonds (the "Policy"). The Policy guarantees the scheduled payment of principal of and interest on the Bonds when due as set forth in the form of the Policy included as an exhibit to this Official Statement.

The Policy is not covered by any insurance security or guaranty fund established under New York, California, Connecticut or Florida insurance law.

Build America Mutual Assurance Company

BAM is a New York domiciled mutual insurance corporation and is licensed to conduct financial guaranty insurance business in all fifty states of the United States and the District of Columbia. BAM provides credit enhancement products solely to issuers in the U.S. public finance markets. BAM will only insure municipal bonds, as defined in Section 6901 of the New York Insurance Law, which are most often issued by states, political subdivisions, integral parts of states or political subdivisions or entities otherwise eligible for the exclusion of income under section 115 of the U.S. Internal Revenue Code of 1986, as amended. No member of BAM is liable for the obligations of BAM.

The address of the principal executive offices of BAM is: 200 Liberty Street, 27th Floor, New York, New York 10281, its telephone number is: 212-235-2500, and its website is located at: www.buildamerica.com.

BAM is licensed and subject to regulation as a financial guaranty insurance corporation under the laws of the State of New York and in particular Articles 41 and 69 of the New York Insurance Law.

BAM's financial strength is rated "AA/Stable" by S&P Global Ratings, a business unit of Standard & Poor's Financial Services LLC ("S&P"). An explanation of the significance of the rating and current reports may be obtained from S&P at www.standardandpoors.com. The rating of BAM should be evaluated independently. The rating reflects the S&P's current assessment of the creditworthiness of BAM and its ability to pay claims on its policies of insurance. The above rating is not a recommendation to buy, sell or hold the Bonds, and such rating is subject to revision or withdrawal at any time by S&P, including withdrawal initiated at the request of BAM in its sole discretion. Any downward revision or withdrawal of the above rating may have an adverse effect on the market price of the Bonds. BAM only guarantees scheduled principal and scheduled interest payments payable by the issuer of the Bonds on the date(s) when such amounts were initially scheduled to become due and payable (subject to and in accordance with the terms of the Policy), and BAM does not guarantee the market price or liquidity of the Bonds, nor does it guarantee that the rating on the Bonds will not be revised or withdrawn.

Capitalization of BAM. BAM's total admitted assets, total liabilities, and total capital and surplus, as of March 31, 2023 and as prepared in accordance with statutory accounting practices prescribed or permitted by the New York State Department of Financial Services were $476.6million, $196.7 million and $279.9 million, respectively.

BAM is party to a first loss reinsurance treaty that provides first loss protection up to a maximum of 15% of the par amount outstanding for each policy issued by BAM, subject to certain limitations and restrictions.

BAM's most recent Statutory Annual Statement, which has been filed with the New York State Insurance Department and posted on BAM's website at www.buildamerica.com, is incorporated herein by reference and may be obtained, without charge, upon request to BAM at its address provided above (Attention: Finance Department). Future financial statements will similarly be made available when published.

BAM makes no representation regarding the Bonds or the advisability of investing in the Bonds. In addition, BAM has not independently verified, makes no representation regarding, and does not accept any responsibility for the accuracy or completeness of this Official Statement or any information or disclosure contained herein, or omitted herefrom, other than with respect to the accuracy of the information regarding BAM, supplied by BAM and presented under the heading "BOND INSURANCE".

Additional Information Available from BAM

Credit Insights Videos. For certain BAM-insured issues, BAM produces and posts a brief Credit Insights video that provides a discussion of the obligor and some of the key factors BAM's analysts and credit committee considered when approving the credit for insurance. The Credit Insights videos are easily accessible on BAM's website at www.buildamerica.com/videos. (The preceding website address is provided for convenience of reference only. Information available at such address is not incorporated herein by reference.)

Credit Profiles. Prior to the pricing of bonds that BAM has been selected to insure, BAM may prepare a pre-sale Credit Profile for those bonds. These pre-sale Credit Profiles provide information about the sector designation (e.g. general obligation, sales tax); a preliminary summary of financial information and key ratios; and demographic and economic data relevant to the obligor, if available. Subsequent to closing, for any offering that includes bonds insured by BAM, any pre-sale Credit Profile will be updated and superseded by a final Credit Profile to include information about the gross par insured by CUSIP, maturity and coupon. BAM pre-sale and final Credit Profiles are easily accessible on BAM's website at www.buildamerica.com/credit-profiles. BAM will produce a Credit Profile for all bonds insured by BAM, whether or not a pre-sale Credit Profile has been prepared for such bonds. (The preceding website address is provided for convenience of reference only. Information available at such address is not incorporated herein by reference.)

Disclaimers. The Credit Profiles and the Credit Insights videos and the information contained therein are not recommendations to purchase, hold or sell securities or to make any investment decisions. Credit-related and other analyses and statements in the Credit Profiles and the Credit Insights videos are statements of opinion as of the date expressed, and BAM assumes no responsibility to update the content of such material. The Credit Profiles and Credit Insight videos are prepared by BAM; they have not been reviewed or approved by the issuer of or the underwriter for the Bonds, and the issuer and underwriter assume no responsibility for their content.

BAM receives compensation (an insurance premium) for the insurance that it is providing with respect to the Bonds. Neither BAM nor any affiliate of BAM has purchased, or committed to purchase, any of the Bonds, whether at the initial offering or otherwise.

OTHER BOND INFORMATION

Ratings on the Bonds

As noted on the cover page of this Official Statement, the Bonds have been assigned an underlying rating of "A" by S&P. No application was made by the City to any other rating agency for the purpose of obtaining any additional underlying rating on the Bonds. S&P is also expected to assign a rating of "AA" to the Bonds based upon the delivery of the Policy by BAM at the time of issuance of the Bonds. In general, rating agencies base their ratings on rating materials furnished to them (which may include additional detail provided by the City that is not presented in this Official Statement) and on the rating agency's independent investigations, studies and assumptions. The rating reflects only the view of the rating agency and an explanation of the significance of the rating may be obtained from S&P. There is no assurance that the rating will be retained for any given period of time or that it will not be revised downward, suspended or withdrawn entirely by the rating agency if, in the judgment of the agency, circumstances so warrant. Any such downward revision or withdrawal of the rating would likely have an adverse effect on the market price of the Bonds. The City has no obligation to take any action, other than file a listed event notification, if the rating of the Bonds is changed, suspended or withdrawn.

Potential Conflicts of Interest

Some or all of the fees of the Underwriter, Underwriter's Counsel, the financial advisor, and Bond Counsel are contingent upon the issuance and sale of the Bonds.

Financial Advisor

PFM Financial Advisors LLC has served as financial advisor to the City relative to the preparation of the Bonds for sale, timing of the sale and other factors relating to the Bonds. The financial advisor has not audited, authenticated or otherwise verified the information set forth in this Official Statement or other information provided relative to the Bonds. PFM Financial Advisors LLC makes no guaranty, warranty or other representation on any matter related to the information contained in the Official Statement. The financial advisor is an independent financial advisory firm and is not engaged in the business of underwriting, marketing, trading or distributing municipal securities. The financial advisor's compensation is contingent on the sale and delivery of the Bonds.

Underwriting

The Bonds are being purchased from the City by Hilltop Securities Inc. (the "Underwriter") at an aggregate purchase price of $20,889,827.25 (the principal amount of the Bonds, less Underwriter's discount of $362,974.70, and plus original issue premium of $1,837,801.95). The initial purchaser may offer and sell the Bonds to certain dealers (including dealers depositing Bonds into investment trusts) and others at prices lower than the initial offering prices set forth on the inside cover hereof, and such initial offering prices may be changed from time to time by the initial purchaser. After the initial public offering, the public offering prices may be varied from time to time.

Official Statement

At the time of delivery of the Bonds, one or more officials of the City will furnish a certificate stating that to the best of his, her or their knowledge this Official Statement, as of its date and as of the date of delivery of the Bonds, does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements contained herein, in light of the circumstances under which they were made, not misleading.

The execution and distribution of this Official Statement have been authorized by the City.

CITY OF RICHLAND, WASHINGTON

By ______/s/______
Brandon Allen, Finance Director

4856-6333-0385

APPENDIX A
THE BOND ORDINANCE

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APPENDIX B
FORM OF OPINION OF BOND COUNSEL

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Stradling Yocca Carlson & Rauth
A Professional Corporation
601 Union Street, Suite 2424
Seattle, WA 98101
206 829 3000
stradlinglaw.com

[Date of Approving Legal Opinion]

City of Richland, Washington

Re: City of Richland, Washington
$19,415,000 Electric Utility Revenue Improvement and Refunding Bonds, 2023

We have served as bond counsel to the City of Richland, Washington (the "City"), in connection with the issuance of the above-referenced Electric Utility Revenue Improvement and Refunding Bonds, 2023 (the "Bonds"), and in that capacity have examined such law and such certified proceedings and other documents as we have deemed necessary to render this opinion. As to matters of fact material to this opinion, we have relied upon representations contained in the certified proceedings and other certifications of public officials furnished to us, without undertaking to verify the same by independent investigation.

The Bonds are issued by the City pursuant to Ordinance No. 2023-06 (the "Bond Ordinance") to provide funds with which (1) to pay the cost of carrying out a portion of the Plan of Additions adopted by the Bond Ordinance, (2) to make a contribution to the reserve fund, (3) to refund the City's outstanding Electric Revenue Improvement and Refunding Bonds, 2013; and (4) to pay the costs of issuance and sale of the Bonds and the administrative costs of the Refunding, all as set forth in the Bond Ordinance.

Reference is made to the Bonds and the Bond Ordinance for the definitions of capitalized terms used and not otherwise defined herein.

We express no opinion herein concerning the completeness or accuracy of any official statement, offering circular or other sales or disclosure material relating to the issuance of the Bonds or otherwise used in connection with the Bonds.

Under the Internal Revenue Code of 1986, as amended (the "Code"), the City is required to comply with certain requirements after the date of issuance of the Bonds in order to maintain the exclusion of the interest on the Bonds from gross income for federal income tax purposes, including, without limitation, requirements concerning the qualified use of Bond proceeds and the facilities financed or refinanced with Bond proceeds, limitations on investing gross proceeds of the Bonds in higher yielding investments in certain circumstances and the arbitrage rebate requirement to the extent applicable to the Bonds. The City has covenanted in the Bond Ordinance to comply with those requirements, but if the City fails to comply with those requirements, interest on the Bonds could become taxable retroactive to the date of issuance of the Bonds. We have not undertaken and do not undertake to monitor the City's compliance with such requirements.

Based upon the foregoing, as of the date of initial delivery of the Bonds to the purchaser thereof and full payment therefor, it is our opinion that under existing law:

1. The City is a duly organized and legally existing charter city of the first class under the laws of the State of Washington.

2. The Bonds have been duly authorized and executed by the City and are issued in full compliance with the provisions of the Constitution and laws of the State of Washington and the ordinances of the City relating thereto.

3. The Bonds constitute valid obligations of the City payable solely out of the Net Revenue of the Electric Utility to be paid into the Bond Fund, except only to the extent that enforcement of payment may be limited by bankruptcy, insolvency or other laws affecting creditors' rights and by the application of equitable principles and the exercise of judicial discretion in appropriate cases.

4. The Bonds are not general obligations of the City.

5. Under existing statutes, regulations, rulings and judicial decisions, the interest on the Bonds is excluded from gross income for federal income tax purposes and is not an item of tax preference for purposes of calculating the federal alternative minimum tax imposed on individuals; however, for tax years beginning after December 31, 2022, with respect to applicable corporations as defined in Section 59(k) of the Internal Revenue Code of 1986, as amended (the "Code"), interest (and original issue discount) with respect to the Bonds might be taken into account in determining adjusted financial statement income for the purposes of computing the alternative minimum tax imposed on such corporations.

This opinion is given as of the date hereof, and we assume no obligation to revise or supplement this opinion to reflect any facts or circumstances that may hereafter come to our attention, or any changes in law that may hereafter occur.

We bring to your attention the fact that the foregoing opinions are expressions of our professional judgment on the matters expressly addressed and do not constitute guarantees of result.

APPENDIX C
2021 AUDITED FINANCIAL STATEMENTS

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APPENDIX D
BOOK-ENTRY TRANSFER SYSTEM

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BOOK-ENTRY TRANSFER SYSTEM

The information in this section concerning the Depository Trust Company, New York, New York ("DTC") and DTC's book-entry system has been obtained from DTC's website at www.dtcc.com and the City takes no responsibility for the accuracy thereof. Beneficial Owners (as hereinafter defined) should therefore confirm the following with DTC or the Participants (as hereinafter defined). For purposes of this section, references to the Issuer mean the City, and references to Agent mean the Bond Registrar. For the purposes of this Official Statement, the term "Beneficial Owner" includes the person for whom the Participant acquires an interest in the Bonds.

1. DTC will act as securities depository for the Bonds. The Bonds will be issued as fully-registered in the name of Cede & Co. (DTC's partnership nominee) or such other name as may be requested by an authorized representative of DTC. One fully-registered Bond certificate will be issued for each maturity of the Bonds in the principal amount of such maturity and will be deposited with DTC.

2. DTC, the world's largest securities depository, is a limited-purpose trust company organized under the New York Banking Law, a "banking organization" within the meaning of the New York Banking Law, a member of the Federal Reserve System, a "clearing corporation" within the meaning of the New York Uniform Commercial Code, and a "clearing agency" registered pursuant to the provisions of Section 17A of the Securities Exchange Act of 1934. DTC holds and provides asset servicing for over 3.5 million issues of U.S. and non-U.S. equity issues, corporate and municipal debt issues, and money market instruments (from over 100 countries) that DTC's participants ("Direct Participants") deposit with DTC. DTC also facilitates the post-trade settlement among Direct Participants of sales and other securities transactions in deposited securities through electronic computerized book-entry transfers and pledges between Direct Participants' accounts. This eliminates the need for physical movement of securities certificates. Direct Participants include both U.S. and non-U.S. securities brokers and dealers, banks, trust companies, clearing corporations, and certain other organizations. DTC is a wholly-owned subsidiary of The Depository Trust & Clearing Corporation ("DTCC"). DTCC is the holding company for DTC, National Securities Clearing Corporation and Fixed Income Clearing Corporation, all of which are registered clearing services. DTCC is owned by the users of its regulated subsidiaries. Access to the DTC system is also available to others such as both U.S. and non-U.S. securities brokers and dealers, banks, and trust companies, and clearing corporations that clear through or maintain a custodial relationship with a Direct Participant, either directly or indirectly ("Indirect Participants"). DTC has Standard & Poor's rating of: AA+. The DTC Rules applicable to its Participants are on file with the Securities and Exchange Commission. More information about DTC can be found at www.dtcc.com (which is not incorporated herein by this reference).

3. Purchases of the Bonds under the DTC system, in denominations of $5,000 or any integral multiple thereof, must be made by or through Direct Participants, which will receive a credit for the Bonds on DTC's records. The ownership interest of each actual purchaser of each Bond ("Beneficial Owner") is in turn to be recorded on the Direct and Indirect Participants' records. Beneficial Owners will not receive written confirmation from DTC of their purchase. Beneficial Owners are, however, expected to receive written confirmations providing details of the transaction, as well as periodic statements of their holdings, from the Direct or Indirect Participant through which the Beneficial Owner entered into the transaction. Transfers of ownership interests in the Bonds are to be accomplished by entries made on the books of Direct and Indirect Participants acting on behalf of Beneficial Owners. Beneficial Owners will not receive certificates representing their ownership interests in the Bonds, except in the event that use of the book-entry system for the Bonds is discontinued.

4. To facilitate subsequent transfers, all Bonds deposited by Participants with DTC are registered in the name of DTC's partnership nominee, Cede & Co. or such other name as may be requested by an authorized representative of DTC. The deposit of Bonds with DTC and their registration in the name of Cede & Co. or such other DTC nominee do not effect any change in beneficial ownership. DTC has no knowledge of the actual Beneficial Owners of the Bonds; DTC's records reflect only the identity of the Direct Participants to whose accounts such Bonds are credited, which may or may not be the Beneficial Owners. The Direct and Indirect Participants will remain responsible for keeping account of their holdings on behalf of their customers.

5. When notices are given, they will be sent by the Bond Registrar to DTC only. Conveyance of notices and other communications by DTC to Direct Participants, by Direct Participants to Indirect Participants, and by Direct Participants and Indirect Participants to Beneficial Owners will be governed by arrangements among them, subject to any statutory or regulatory requirements as may be in effect from time to time.

6. Redemption notices will be sent to DTC. If less than all of the Bonds are being redeemed, DTC's practice is to determine by lot the amount of the interest of each Direct Participant in such issue to be redeemed.

7. Neither DTC nor Cede & Co. (nor any other DTC nominee) will consent or vote with respect to the Bonds unless authorized by a Direct Participant in accordance with DTC's MMI Procedures. Under its usual procedures, DTC mails an Omnibus Proxy to the City as soon as possible after the record date. The Omnibus Proxy assigns Cede & Co.'s consenting or voting rights to those Direct Participants to whose accounts Bonds are credited on the record date (identified in a listing attached to the Omnibus Proxy).

8. Redemption proceeds, distributions, and dividend payments on the Bonds will be made to Cede & Co. or such other nominee as may be requested by an authorized representative of DTC. DTC's practice is to credit Direct Participants' accounts upon DTC's receipt of funds and corresponding detail information from the City or the Bond Registrar, on payable date in accordance with their respective holdings shown on DTC's records. Payments by Participants to Beneficial Owners will be governed by standing instructions and customary practices, as is the case with securities held for the accounts of customers in bearer form or registered in "street name," and will be the responsibility of such Participant and not of DTC, the Bond Registrar, or the City, subject to any statutory or regulatory requirements as may be in effect from time to time. Payment of redemption proceeds, distributions, and dividend payments to Cede & Co. (or any other nominee as may be requested by an authorized representative of DTC) is the responsibility of the City or the Bond Registrar, disbursement of such payments to Direct Participants will be the responsibility of DTC, and disbursement of such payments to the Beneficial Owners will be the responsibility of Direct and Indirect Participants.

9. DTC may discontinue providing its services as securities depository with respect to the Bonds at any time by giving reasonable notice to the City and the Bond Registrar. Under such circumstances, in the event that a successor securities depository is not obtained, Bond certificates are required to be printed and delivered.

10. Issuer may decide to discontinue use of the system of the book-entry transfers through DTC (or a successor securities depository). In that event, Bond certificates will be printed and delivered to DTC.

The information in this section concerning DTC and DTC's book-entry system has been obtained from sources that Issuer believes to be reliable, but Issuer takes no responsibility for the accuracy thereof.

APPENDIX E
SPECIMEN MUNICIPAL BOND INSURANCE POLICY

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MUNICIPAL BOND INSURANCE POLICY

ISSUER: [NAME OF ISSUER]

Policy No: _____

MEMBER: [NAME OF MEMBER]

BONDS: $__________ in aggregate principal amount of [NAME OF TRANSACTION] [and maturing on]

Effective Date: _________

Risk Premium: $__________
Member Surplus Contribution: $ _________
Total Insurance Payment: $_________

BUILD AMERICA MUTUAL ASSURANCE COMPANY ("BAM"), for consideration received, hereby UNCONDITIONALLY AND IRREVOCABLY agrees to pay to the trustee (the "Trustee") or paying agent (the "Paying Agent") for the Bonds named above (as set forth in the documentation providing for the issuance and securing of the Bonds), for the benefit of the Owners or, at the election of BAM, directly to each Owner, subject only to the terms of this Policy (which includes each endorsement hereto), that portion of the principal of and interest on the Bonds that shall become Due for Payment but shall be unpaid by reason of Nonpayment by the Issuer.

On the later of the day on which such principal and interest becomes Due for Payment or the first Business Day following the Business Day on which BAM shall have received Notice of Nonpayment, BAM will disburse (but without duplication in the case of duplicate claims for the same Nonpayment) to or for the benefit of each Owner of the Bonds, the face amount of principal of and interest on the Bonds that is then Due for Payment but is then unpaid by reason of Nonpayment by the Issuer, but only upon receipt by BAM, in a form reasonably satisfactory to it, of (a) evidence of the Owner's right to receive payment of such principal or interest then Due for Payment and (b) evidence, including any appropriate instruments of assignment, that all of the Owner's rights with respect to payment of such principal or interest that is Due for Payment shall thereupon vest in BAM. A Notice of Nonpayment will be deemed received on a given Business Day if it is received prior to 1:00 p.m. (New York time) on such Business Day; otherwise, it will be deemed received on the next Business Day. If any Notice of Nonpayment received by BAM is incomplete, it shall be deemed not to have been received by BAM for purposes of the preceding sentence, and BAM shall promptly so advise the Trustee, Paying Agent or Owner, as appropriate, any of whom may submit an amended Notice of Nonpayment. Upon disbursement under this Policy in respect of a Bond and to the extent of such payment, BAM shall become the owner of such Bond, any appurtenant coupon to such Bond and right to receipt of payment of principal of or interest on such Bond and shall be fully subrogated to the rights of the Owner, including the Owner's right to receive payments under such Bond. Payment by BAM either to the Trustee or Paying Agent for the benefit of the Owners, or directly to the Owners, on account of any Nonpayment shall discharge the obligation of BAM under this Policy with respect to said Nonpayment.

Except to the extent expressly modified by an endorsement hereto, the following terms shall have the meanings specified for all purposes of this Policy. "Business Day" means any day other than (a) a Saturday or Sunday or (b) a day on which banking institutions in the State of New York or the Insurer's Fiscal Agent (as defined herein) are authorized or required by law or executive order to remain closed. "Due for Payment" means (a) when referring to the principal of a Bond, payable on the stated maturity date thereof or the date on which the same shall have been duly called for mandatory sinking fund redemption and does not refer to any earlier date on which payment is due by reason of call for redemption (other than by mandatory sinking fund redemption), acceleration or other advancement of maturity (unless BAM shall elect, in its sole discretion, to pay such principal due upon such acceleration together with any accrued interest to the date of acceleration) and (b) when referring to interest on a Bond, payable on the stated date for payment of interest. "Nonpayment" means, in respect of a Bond, the failure of the Issuer to have provided sufficient funds to the Trustee or, if there is no Trustee, to the Paying Agent for payment in full of all principal and interest that is Due for Payment on such Bond. "Nonpayment" shall also include, in respect of a Bond, any payment made to an Owner by or on behalf of the Issuer of principal or interest that is Due for Payment, which payment has been recovered from such Owner pursuant to the United States Bankruptcy Code in accordance with a final, nonappealable order of a court having competent jurisdiction. "Notice" means delivery to BAM of a notice of claim and certificate, by certified mail, email or telecopy as set forth on the attached Schedule or other acceptable electronic delivery, in a form satisfactory to BAM, from and signed by an Owner, the Trustee or the Paying Agent, which notice shall specify (a) the person or entity making the claim, (b) the Policy Number, (c) the claimed amount, (d) payment instructions and (e) the date such claimed amount becomes or became Due for Payment. "Owner" means, in respect of a Bond, the person or entity who, at the time of Nonpayment, is entitled under the terms of such Bond to payment thereof, except that "Owner" shall not include the Issuer, the Member or any other person or entity whose direct or indirect obligation constitutes the underlying security for the Bonds.

BAM may appoint a fiscal agent (the "Insurer's Fiscal Agent") for purposes of this Policy by giving written notice to the Trustee, the Paying Agent, the Member and the Issuer specifying the name and notice address of the Insurer's Fiscal Agent. From and after the date of receipt of such notice by the Trustee, the Paying Agent, the Member or the Issuer (a) copies of all notices required to be delivered to BAM pursuant to this Policy shall be simultaneously delivered to the Insurer's Fiscal Agent and to BAM and shall not be deemed received until received by both and (b) all payments required to be made by BAM under this Policy may be made directly by BAM or by the Insurer's Fiscal Agent on behalf of BAM. The Insurer's Fiscal Agent is the agent of BAM only, and the Insurer's Fiscal Agent shall in no event be liable to the Trustee, Paying Agent or any Owner for any act of the Insurer's Fiscal Agent or any failure of BAM to deposit or cause to be deposited sufficient funds to make payments due under this Policy.

To the fullest extent permitted by applicable law, BAM agrees not to assert, and hereby waives, only for the benefit of each Owner, all rights (whether by counterclaim, setoff or otherwise) and defenses (including, without limitation, the defense of fraud), whether acquired by subrogation, assignment or otherwise, to the extent that such rights and defenses may be available to BAM to avoid payment of its obligations under this Policy in accordance with the express provisions of this Policy. This Policy may not be canceled or revoked.

This Policy sets forth in full the undertaking of BAM and shall not be modified, altered or affected by any other agreement or instrument, including any modification or amendment thereto. Except to the extent expressly modified by an endorsement hereto, any premium paid in respect of this Policy is nonrefundable for any reason whatsoever, including payment, or provision being made for payment, of the Bonds prior to maturity. THIS POLICY IS NOT COVERED BY THE PROPERTY/CASUALTY INSURANCE SECURITY FUND SPECIFIED IN ARTICLE 76 OF THE NEW YORK INSURANCE LAW. THIS POLICY IS ISSUED WITHOUT CONTINGENT MUTUAL LIABILITY FOR ASSESSMENT.

In witness whereof, BUILD AMERICA MUTUAL ASSURANCE COMPANY has caused this Policy to be executed on its behalf by its Authorized Officer.

BUILD AMERICA MUTUAL ASSURANCE COMPANY

By: ____

Authorized Officer

Notices (Unless Otherwise Specified by BAM)

Email:
claims@buildamerica.com
Address:
200 Liberty Street, 27th floor
New York, New York 10281
Telecopy:
212-962-1524 (attention: Claims)

Credit Highlights

- S&P Global Ratings assigned its 'A' long-term rating to Richland, Wash.'s approximately $19.5 million series 2023 electric revenue improvement bonds.
- At the same time, S&P Global Ratings affirmed its 'A' long-term rating on the city's electric revenue bonds outstanding.
- The outlook is stable.

Security

Net electric system revenues secure the bonds. Officials plan to use Series 2023 bond proceeds to fund $8 million electric utility system capital improvements and refund series 2013B bonds outstanding for interest cost savings. As of Dec. 31, 2022, the electric system had about $74 million of debt outstanding. We consider bond provisions as standard and credit neutral.

Credit overview

The rating reflects our opinion of the utility's solid fixed-cost coverage (FCC), which improved to 1.49x in 2022 (based on unaudited financials) and 1.58x in 2021 from 1.35x in the previous year; and increased liquidity in recent years, reflecting $13.3 million in unrestricted cash (or 78 days of operating expenses) based on unaudited 2022 financials. We view the utility's improving financial position as attributable to comprehensive operational and financial policies (including a minimum 90 days of operating costs and a debt service coverage target of 1.75x) that management has taken steps to meet or maintain, along with robust cost recovery through rate adjustments.

The rating further reflects our view of the utility's limited exposure to operational risks as an offtaker of Bonneville Power Authority (BPA). However, given hydroelectric power is its primary source, BPA's generating capacity is reliant on precipitation and snowpack, and in our view, climate change could affect the amount, timing, and availability of hydroelectric generation, exposing BPA and its distributors, including Richland, to potential power cost volatility. Somewhat mitigating this is the utility's high degree of revenue-raising flexibility to pass through higher rates to ratepayers as needed, largely due to its competitive rates (system rates were 91% of the state average in 2021) and above-average incomes.

The rating further reflects our opinion of the utility's following factors:

- Robust service area economy in the Richland-Kennewick metropolitan statistical area, with 44% electric revenue obtained from residential customers and the lack of customer concentration among its top 10 customers;
- Sound risk management and operational planning around environmental compliance, system reliability, and emergency preparedness, which helps enhance operational stability; and
- High debt burden profile marked by a debt-to-capitalization ratio of 51% as of fiscal 2022 with a $62.5 million capital plan for 2023-2028, which management plans to fund with surplus revenue, grants, and debt.

Environmental, social, and governance

Environmental factors, including energy transition risks, are credit neutral within our analysis. The utility has indirect exposure to BPA's potential environmental compliance costs and is subject to the state's Clean Energy Transition Act and Energy Independence Act. Nevertheless, we view positively that the utility obtained almost all its electricity from non-carbon-emitting resources, as it limits the utility's exposure to the costs and operational challenges of carbon-related regulations. We also view favorably that the city works with an external consultant to regularly update an integrated resource plan and is on track to meet the targets set out by both regulations.

We view the utility's social factors as credit neutral, as evidenced by its system rates that are consistently below the state average in recent years. Although there will be no rate changes through 2023, management plans to modestly increase rates in 2024 and 2026. However, we believe this is unlikely to materially weaken rate affordability. Adding to social pressures, S&P Global Ratings projects that the U.S. economy will likely fall into a shallow recession in 2023, tempered by generally strong labor demand. (See "Economic Outlook U.S. Q2 2023: Still Resilient, Downside Risks Rise," published March 27, 2023, on RatingsDirect.) Consequently, we continue to monitor the strength and stability of the utility’s revenue stream for evidence of delinquent payments or other revenue erosion because rising consumer prices and interest rates are whittling consumers' discretionary income.

We view the utility's exposure to governance factors as also credit neutral, as they include full rate-setting autonomy, liquidity targets, and annually updated capital plan and financial forecasts.

Outlook

The stable outlook reflects our view of the utility’s revenue stability supported by its steady customer base, loading-following full-requirements contract with BPA, and competitive rates. We also expect that within the next two years, management will continue to recover costs through rate adjustments to preserve the utility’s financial profile and support future capital needs. Lastly, we anticipate management will likely maintain credit-supportive operational, financial, and risk management policies, which support its stable operational profile.

Downside scenario

Although we believe it is unlikely in the next two years, we could lower the rating if financial metrics deteriorate significantly, either due to higher-than-projected debt needs to fund capital projects, or the failure to recover unbudgeted power costs spurred by weak hydrology conditions.

Upside scenario

We could raise the rating within the outlook period if liquidity and debt meaningfully improve on a sustained basis.

Credit Opinion

The utility has a stable customer base with residential customers contributing about 44% of revenue in 2021. Residents benefit from employment opportunities within Richland and the greater tri-cities area. The city is a center of production and research into energy, medicine, and high technology. The service area is characterized by high incomes and access to a broad and diverse employment base. Since 1942, the federal government's 570-square-mile Hanford Nuclear Reservation, north of and adjacent to the city, has dominated the local economy. In 1989, Washington State, the U.S. Environmental Protection Agency, and others signed an agreement to clean up the Hanford area. Other major industries include agriculture, biotech, and manufacturing, with an increasing medical and research presence. The top 10 customers, representing 25% of revenue in 2022, have a reduced concentration due to overall increased load from largely residential customers. The leading customer, Lamb Weston/ConAgra, accounted for about 7% of retail revenue in 2022. Median household effective buying income is very strong, at 127% of the national level in 2022, which is the highest among the tri-cities.

We view favorably the utility's full-requirements, load-following contract with BPA because of the authority's size and sophistication, as well as its shaft and power supply diversity. Under this contract that runs through 2028, the utility receives about 90% of its power at BPA's tier 1 rates and meets the tier 2 requirements (about 10% of its power) by using a blend of non-federal market purchases from Northwest Intergovernmental Energy Supply. Energy sourced from BPA's tier 1 power is predominantly supplied by federal hydroelectric projects and complemented by nuclear projects. Consequently, the utility has a very low carbon footprint. The utility also secured a power purchase agreement for output from 4 megawatts of renewable solar as part of the Horn Rapids solar, storage, and training site. BPA's 2021 fuel mix consisted of 83% of hydro, 11% nuclear, 1% from other renewables sources, and 5% from unidentified sources.

The utility has exhibited moderately improved and generally robust financial metrics in recent years. In our FCC calculation, we treat a percentage of BPA costs as debtlike rather than as an operating cost. FCC averaged about 1.43x from 2019-2021 and is estimated to be 1.49x in 2022 based on unaudited financials, which we consider robust. We view the current liquidity position as sufficient for a distribution-only system. Management aims to maintain future liquidity near current levels; however, we note that current inflationary pressures and any unexpected capital or operating costs could meaningfully pressure liquidity in the future.

Richland, Washington --Key credit metrics			
	--Fiscal year ended Dec. 31--		
	2021	**2020**	**2019**
Operational metrics			
Electric customer accounts	26,658	25,613	24,966
% of electric retail revenues from residential customers	44	45	44
Top 10 electric customers' revenues as % of total electric operating revenue	25	31	31
Service area median household effective buying income as % of U.S.	127	121	127
Weighted average retail electric rate as % of state	91	94	100
Financial metrics			
Gross revenues ($000s)	76,383	73,858	75,885
Total operating expenses less depreciation and amortization ($000s)	58,591	61,058	62,958
Debt service ($000s)	6,056	6,005	5,767
Debt service coverage (x)	3.1	2.2	2.4
Fixed-charge coverage (x)	1.58	1.35	1.35
Total available liquidity ($000s)*	13,701	6,703	8,444
Days' liquidity	85	40	49
Total on-balance-sheet debt ($000s)	77,583	73,417	76,739
Debt-to-capitalization (%)	52	54	57

Related Research

Through The ESG Lens 3.0: The Intersection Of ESG Credit Factors And U.S. Public Finance Credit Factors , March 2, 2022

UTILITY ADVISORY COMMITTEE AGENDA ITEM COVERSHEET

Richland Washington

Meeting Date: 7/11/2023 Agenda Category: Items of Business

Prepared By: Clint Whitney, Energy Services Director

Subject:
Net Metering Study with Washington Public Utility District Association

Department:
Energy Services

Recommended Motion:
No action needed. Staff will follow up with results of the study at the January 2024 UAC meeting.

Summary:
Washington electric municipal utilities, public utility districts, electric cooperatives, and investor-owned utilities are joining together to commission a net metering study. Chapter 80.60 RCW requires electric utilities to offer net metering for retail customers with electrical generation. The objective of the study is to evaluate the costs and benefits of net metering for rate customers using data from a representative of Washington electric utilities. The study is expected to identify if there is any electric rate class subsidy caused from net metering.

The Washington Public Utility Districts Association (WPUDA) will issue and manage the contract for the study. Energy Environmental Economics (E3) has proposed a scope of work in the amount of $468,500 plus tax with each participating utility paying its prorated share based on its annual energy sales and number of customers. The City's share of the expense would be $5,000. Attached is E3 proposed scope of work for the net metering study.

City staff is supportive of the net metering study and has recommended City Council approve a resolution authorizing an agreement between the City and WPUDA to complete the study. City Council will be considering the resolution for the net metering study at the July 6th Council meeting.

If approved, the E3 study will be completed by December 2023 with the results available to be presented at the January 2024 UAC meeting.

Fiscal Impact:
The City's participation in the study will be funded out of the approved 2023 budget for the Electric Fund in the amount not to exceed $5,000.

Attachments:
1. Net Metering Study - Proposed Scope and Budget with E3

WA Utilities NEM Evaluation

Proposed Scope and Budget

May 11, 2023

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Arne Olson

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San Francisco, CA 94104

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415-722-9708

Energy+Environmental Economics

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1 Overview

E3 is pleased to submit this scope of work to support the Washington PUD Association (WPUDA) and other Washington utilities in evaluating net energy metering (NEM).

1.1 Proposed Tasks

The proposed tasks are:

1. **Engage with diverse stakeholders through a technical advisory committee**
2. **Develop a database of interconnected NEM solar projects**
3. **Calculate representative benefits of customer solar**
4. **Evaluate existing NEM programs**
5. **Review rate design options**
6. **Additional utilities for detailed study**

More detail on these tasks is provided below.

1.2 "Detailed Study Utilities"

Due to the large number of utilities in Washington State, E3 proposes to perform detailed analysis for a set of four "detailed study utilities" and then to leverage this analysis to estimate statewide impacts. The set of utilities should reflect different utility ownership structures as well as geographic locations.

Table 1 provides an illustrative set of detailed study utilities. The final set of utilities for detailed analysis can be updated based on feedback from the utilities.

The project budget provided in this proposal reflects a detailed study of four utilities. Beyond the initial four, additional utilities can be evaluated in detail at an additional cost, as described in the section **Project Budget**.

Table 1: Example set of "detailed study utilities" for in-depth analysis

Utility	Ownership Type	Location (relative to Cascades)
Puget Sound Energy	IOU	West
Tacoma Power	Municipal	West
Kittitas County	PUD	East
Okanogan County	Co-op	East

1.3 Stakeholder management

This study has a wide range of potential stakeholders, including numerous utility stakeholders as well as external stakeholders. The scope of work and budget provided here assume that the utilities and/or other parties could manage a significant portion of the stakeholder engagement for this study. Specifically, this proposal assumes that E3 would **not** be responsible for the following two roles:

- **Utility point of contact**. This proposal assumes that the utilities would designate a single point of contact who would be responsible for managing data requests, feedback, and other communication among utilities and between E3 and individual utilities. This person (or group) would be responsible for tasks such as:
  - Following up with utilities on E3 data requests
  - Organizing meetings among utilities and E3
  - Collecting utility feedback on draft work products and summarizing feedback for E3
- **Technical Advisory Committee (TAC) organizer**. This proposal assumes that the utilities would designate a point of contact who would be responsible for organizing the Technical Advisory Committee (TAC). This person or group could be a utility representative or staff from the Washington Department of Commerce or Utilities and Transportation Commission, or from another party. This person (or group) would be responsible for tasks such as:
  - Recruiting members for the TAC
  - Scheduling and hosting TAC meetings
  - Collecting TAC member feedback
  - Summarizing feedback for E3 and for the final report

More details on E3’s anticipated role in the TAC are provided in Task 1 below.

2 Detailed Task Descriptions

2.1 Task 1: Stakeholder engagement and technical advisory committee

Net Energy Metering (NEM) is a complex topic and stakeholders in other jurisdictions have expressed a wide range of perspectives about the potential costs and benefits of NEM. A robust stakeholder process can provide a forum to air diverse viewpoints and help ensure that the cost-benefit study is comprehensive and credible. For Task 1, E3 suggests that the utilities convene a Technical Advisory Committee consisting of representatives from stakeholder groups such as environmental advocates, ratepayer advocates, state agencies or regulatory bodies, rooftop solar developers, large electricity users, advocates for disadvantaged communities, and tribal communities to provide input from a variety of perspectives. The TAC would initially provide feedback on study inputs, proposed methodology, and key metrics. Once draft results were ready, the TAC would provide feedback on study results and contextualization.

Although stakeholders may have interests in certain outcomes, the economic impacts of NEM programs can be evaluated using widely recognized principles of regulatory economics such cost-effectiveness tests from the national standard practice manual.[1] Through the TAC, stakeholders would have the opportunity to provide feedback on inputs, methodology, and even on results. However, the results of the study would be based on data and transparent economic analysis, and stakeholders on the TAC would not be able to alter or block any results of the study.

For this project, E3 proposes that TAC recruitment and organization be taken on by a local party such as a utility or representatives from the WA Department of Commerce and/or Utilities and Transportation Commission. E3 will support the TAC organizers by suggesting agenda items and developing materials for each TAC meeting and will be available to present at these meetings. Finally, the TAC organizers would be responsible for taking notes and summarizing feedback from TAC members for E3 to integrate into our analysis and report.

Task 1 Deliverables:

+ Support TAC organizers with developing agenda and materials for 3 TAC meetings
+ Participation in 3 TAC meetings

2.2 Task 2: Develop database of NEM solar systems

To evaluate the impact of NEM programs in Washington State, key data are needed on existing NEM solar systems. In Task 2, E3 would work with the detailed study utilities to develop a WA NEM Systems Database with key data regarding each customer solar system interconnected under the NEM program.

[1] https://www.nationalenergyscreeningproject.org/national-standard-practice-manual/

A potential model for this database exists in California. The California Public Utilities Commission works with the three large Investor-Owned Utilities (IOUs) and other stakeholders to maintain a database called CA DG Stats ("California Distributed Generation Statistics"). CA DG Stats is best known for its online dashboard, as shown in **Figure 1**. However, CA DG Stats also includes downloadable data files that include detailed information about every interconnected NEM project in the IOU service territories.

The CA DG Stats raw data files were instrumental in developing the "NEM 2.0 Lookback Study," an evaluation of California's NEM 2.0 study performed by Verdant Associates and E3 for the California PUC.[2] Similar data would be valuable to perform a NEM evaluation in Washington State.

Figure 1: Example of the CA DG Stats dashboard [3]

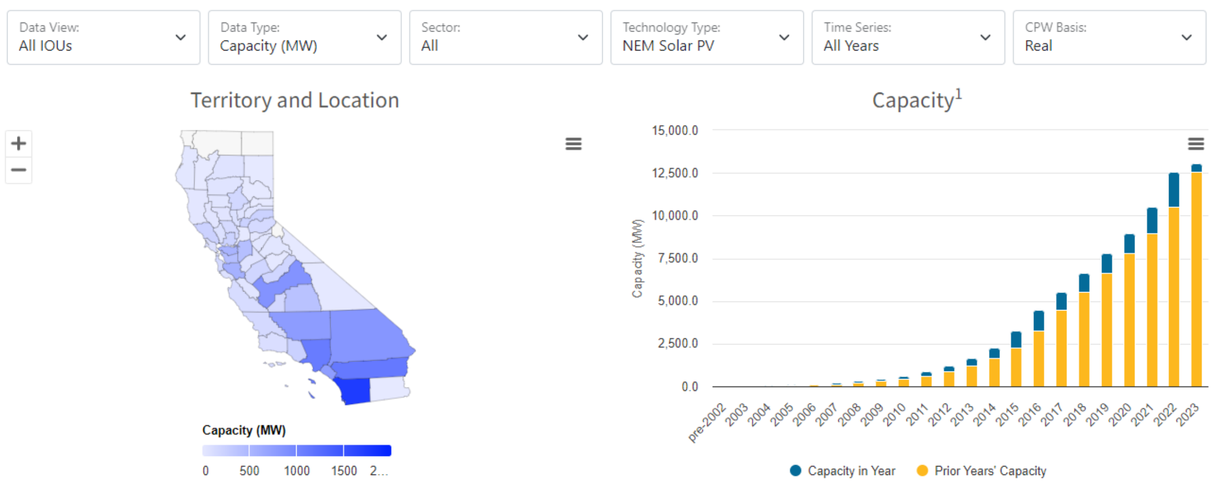

Table 2 provides an overview of example data that could be included in the WA NEM Systems Database.

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[2] https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/net-energy-metering-nem/nem-evaluation/nem-2_lookback_study.pdf

[3] https://www.californiadgstats.ca.gov/charts/

Table 2: Key data for the WA NEM Systems Database (characteristics per system) – provided for the detailed study utilities

Minimum data per system
• Unique ID (*e.g.,* interconnection application ID) • Utility • Solar system size (kW-AC) • Interconnection year • Customer class
Additional data per system (if available)
• Leased or owned system • If leased: $/month cost, escalation rate, and term of lease • If owned: solar system cost before tax credits ($ or $/kW-AC) • Paired battery kWh • Paired battery cost ($ or $/kWh) • Zip code • City • Rate schedule • Low-income program enrollment (LIHEAP, payment programs, etc.) • Customer premise information (own vs. rent, single- vs. multi-family vs. non-residential, etc).
Additional confidential data per system (if available)
• Pre-interconnection annual load (kWh/year) • Post-interconnection annual load (net kWh/year)

To develop statewide results, data would also be needed from the other utilities in Washington State. However, this data could be much less granular for utilities who are not among the detailed study utilities. Specifically, the remaining utilities could simply provide the total interconnected NEM solar capacity (MW AC) as a single number.

Task 2 Deliverables:

+ Data request to detailed study utilities to support WA NEM Systems Database
+ Simple data request to other utilities
+ WA NEM Systems Database (spreadsheet format)
+ Summary charts and figures

2.3 Task 3: Evaluate representative benefits

In Task 3, E3 will work with the detailed study utilities and the TAC to evaluate the benefits associated with rooftop solar systems. These include cost savings to electric utilities that are passed on to electricity customesr. These “avoided costs” represent the system value of marginal load reduction or customer generation. These avoided costs would be forward-looking, reflecting the period from 2023-2045. This forecast of marginal costs is important to accurately reflect the value over time of incremental customer solar to the electric system.

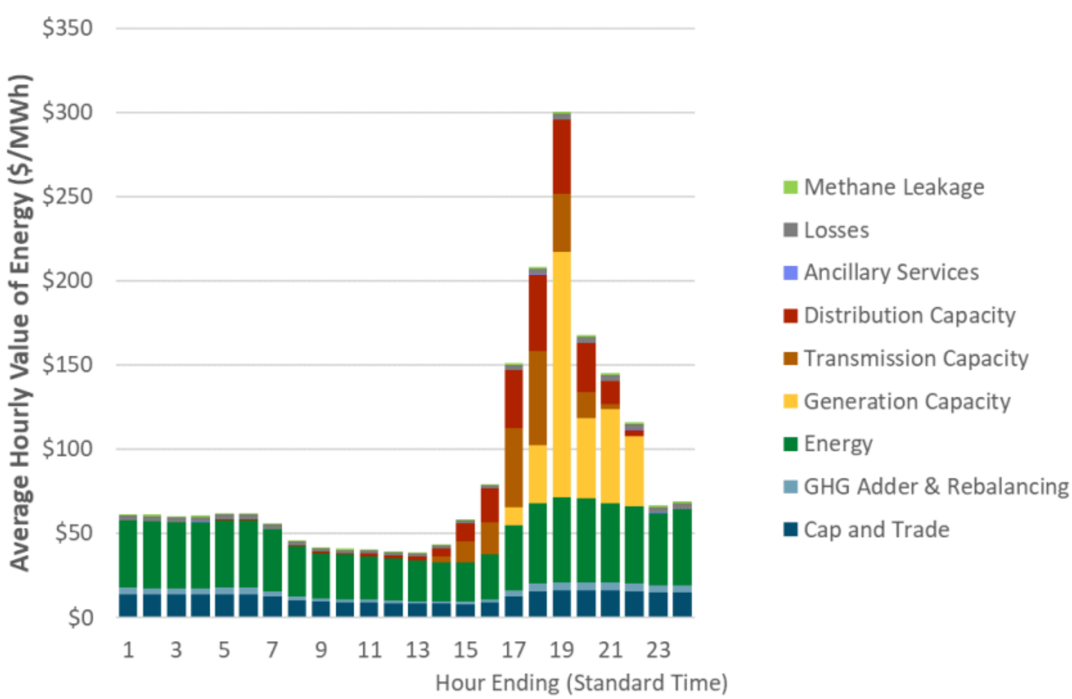
These marginal costs would be developed for all 8760 hours of the year. Alternatively, a representative solar profile could be used to generate a single annual $/MWh "solar avoided cost" per year. However, this simplified approach would not enable modeling the system benefits of customer solar+storage, which would provide power in different hours than standalone solar.

Other benefits include reduced CO_2 emissions and emissions of harmful air pollutants such as NOx and SOx, reduced water consumption, land-use benefits, resilience, and others. These benefits may accrue to others besides utility ratepayers. As a result, E3 will consider different "perspectives" commonly utilized in utility customer program evaluation:

+ **Ratepayer Perspective**: this perspective captures all benefits that accrue to electricity consumers.
+ **Societal Perspective**: this perspective captures all benefits that accrue to society at large.
+ **Solar Adopter Perspective**: this perspective captures all benefits that accrue directly to the customer that adopts NEM solar.

An example of marginal costs that E3 has quantified for the California Public Utilities Commission (CPUC) is shown in **Figure 2**. This figure shows the hourly average over all days of the year and is broken down by avoided cost components.

Figure 2: Average hourly avoided costs from the CPUC Avoided Cost Calculator



Marginal costs would include the following components:

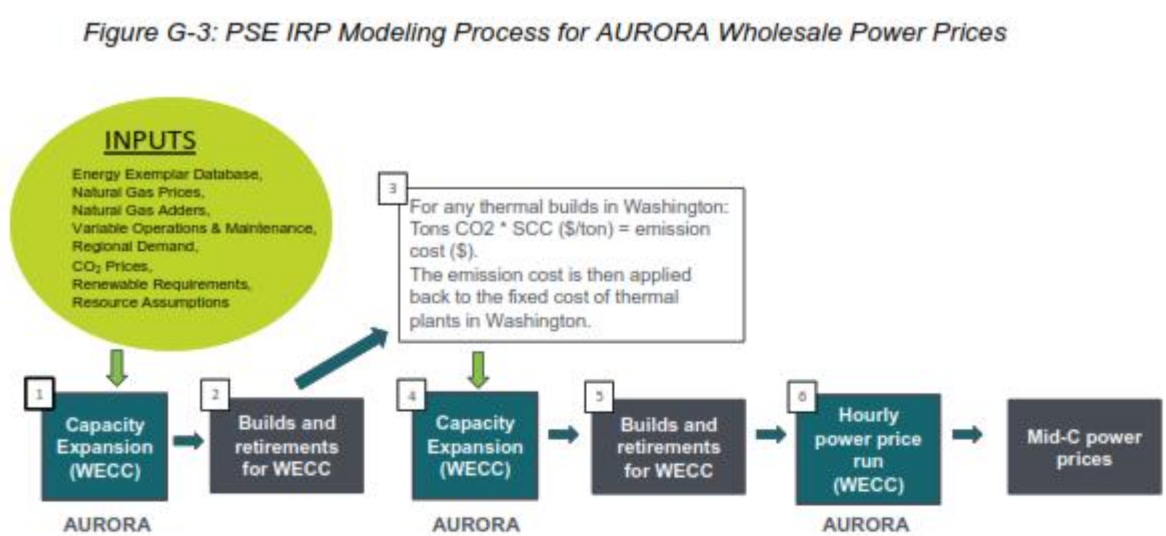
2.3.1 Energy avoided costs

Energy is likely to be the most significant utility avoided cost component for customer solar. At any given time, the energy component of solar value is equal to wholesale energy prices the utility would see for buying or selling electricity, adjusted for line losses.

E3 proposes to work with the utilities to develop energy price forecasts for the Mid-Columbia ("Mid-C") trading hub. These forecasts should reflect changes over time in fossil generation, renewable resources, energy storage, and distributed energy resources as well as key changes in state policy and in technology costs and characteristics over time.

As an example approach, Puget Sound Energy's 2021 IRP report describes using the AURORA model to forecast wholesale power prices at Mid-C.

Figure 3: PSE IRP Modeling Process for AURORA Wholesale Power Prices.[4]



Ultimately, hourly forecasts may be simplified into either 12x24 month-hour averages or even a single annual $/kWh solar-weighted energy avoided cost. Annual forecasts should be developed through the year 2045.

2.3.2 Generation capacity avoided costs

E3 proposes to develop generation capacity avoided costs based on a non-emitting proxy resource, such as a hydrogen- or biofuel-powered combustion turbine. The proxy resource will be determined through consultation with utilities and a review of recent studies for the Pacific Northwest. Although lithium-ion batteries are commonly used as the proxy resource for generation capacity in other jurisdictions, that

[4] Page G-6, figure G-3. https://www.pse.com/-/media/PDFs/IRP/2021/appendix/18-IRP21_AppG_033021.pdf?modified=20220307202830

approach is not recommended in the Northwest where the system is long on reservoir storage, leading to low capacity value for additional battery storage.[5]

E3 will also work with utilities to forecast the approximate hours of generation capacity need. This could leverage work from utility planning, from the Western Power Pool, and/or from the Northwest Power and Conservation Council.

2.3.3 Transmission capacity avoided costs

E3 proposes to use transmission marginal cost studies from the utilities or the Bonneville Power Administration where available, or to estimate transmission marginal costs based on other utilities' studies. In addition, E3 would develop a Peak Load Allocation Factor (PCAF) approach using load or temperature to allocate these costs over the 8760 hours of the year. This is necessary to ensure proper crediting of demand side resources that are available during the hours with highest transmission utilization.

2.3.4 Distribution capacity avoided costs

E3 would work with utilities to develop distribution capacity avoided costs. E3 has experience calculating near-term distribution costs based on opportunities for distribution deferral, yielding near-term distribution avoided costs in the range of \$4 - \$15/kW-yr, whereas long-term distribution costs developed from general rate case data range from \$20 - \$206/kW-yr. Finally, as with Transmission Capacity, E3 would develop PCAFs to allocate these costs over the 8760 hours of the year to ensure proper crediting of demand side resources that are available during the hours with highest distribution utilization.

2.3.5 GHG avoided costs

Under Washington's Clean Energy Transition Act, electric ratepayers benefit from clean energy investments through reduced need to acquire carbon allowances. GHG avoided costs would be developed using marginal grid emissions rates associated with the energy avoided cost forecasts. These emissions rates would be adjusted to reflect system rebalancing under CETA's 2030 carbon neutral electricity standard. Rebalancing is meant to reflect that, if marginally less customer solar were installed, replacement resources would need to be partially or fully zero-carbon due to the clean energy standard. GHG avoided costs would be capped at the non-compliance costs under CETA.

2.3.6 Other benefit categories

As discussed above, customer solar has additional benefits that do not accrue directly to electric ratepayers or are not reflected in the above categories. Through consultation with utilities and the TAC, E3 proposes to develop a list of potential benefits of solar to evaluate as well as the corresponding

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[5] See, e.g., PSE IRP "Resource Adequacy Analysis," Figure 7-19. https://www.pse.com/-/media/PDFs/IRP/2021/chapters/07IRP21_Ch7_032921.pdf?modified=20220307201457

beneficiaries. These benefits may fall into different categories based on who receives the benefits.

For example, in prior work for the Sacramento Municipal Utility District (SMUD), E3 worked with SMUD and with a Technical Working Group (TWG) to develop a list of 24 benefits from customer solar. **Figure 4** lists each benefit identified by the SMUD study TWG, categorizes each benefit into an E3-proposed category, and describes which items benefit utility ratepayers, society at large, and/or solar customers.

Figure 4: Components of customer solar value recommended by the Technical Working Group from the SMUD Value of Solar study.[6]

Category	ID [10]	TWG Value Description (abbreviated)	E3 Value Component(s)	Ratepayer	Societal	Solar Customer
Energy	1	Avoided energy, including GHG / RPS requirements	Energy, GHG, Ancillary Services	✓	✓	
	2	Integration costs	Integration	✓	✓	
	3	Higher marginal cost of emissions (intermittency)	*Qualitative*	✓	✓	
Generation Capacity	4	Resource adequacy	Generation Capacity	✓	✓	
	5	Resource flexibility (increased need for flexibility)	Integration	✓	✓	
Financial Risk	6	Fuel price risk reduction	Fuel Price Risk	✓	✓	
	7	Increases in energy price volatility	Energy Price Volatility	✓	✓	
	8	Sunk cost of Emission Reduction Credits	*Qualitative*			
Variable Operating	9	Decreased thermal operations	Energy	✓	✓	
	10	Increased standby costs	Integration	✓	✓	
Criteria Emissions	11	Criteria emissions reductions	Criteria Pollutants		✓	
Carbon Emissions	12	Carbon reductions beyond SMUD compliance requirements	Carbon Emission Reductions		✓	
Land & Water Use	13	Reduced land and water usage	Land use; water use		✓	
Equity	14	Reduced energy burden for low income customers	*Qualitative*		✓	✓
Resilience	15	Customer ability to meet critical needs	Resilience			✓
Reliability	16	Restoring service or preventing outages in an emergency	Reliability	✓	✓	
Emotional / Political	17	Engaging customers through NEM, changing their relationship w/ energy	*Qualitative*		✓	✓
Local Economy	18	Jobs and local economic growth resulting from rooftop solar	*Qualitative*		✓	
Transmission	19	Transmission capacity	Transmission Capacity	✓	✓	
	20	Transmission line losses	Line Losses	✓	✓	
Distribution	21	Distribution capacity	Distribution Capacity	✓	✓	
	22	Distribution line losses	Line Losses	✓	✓	
	23	Grid modernization	*Qualitative*	✓	✓	
	24	Voltage / power quality	Voltage / power quality	✓	✓	

[6] https://www.smud.org/-/media/Documents/Rate-Information/2022-2023-Rate-Action/VOSstudy.ashx, see p10

In this study, E3 proposes to work with WA utilities and with the TAC to develop a list of solar benefits and to categorize the group(s) that would benefit from each one. Where possible, E3 will then work to estimate the monetary value of each benefit for inclusion in the relevant cost tests.

Task 3 Deliverables:

+ Data request to utilities
+ Working session(s) with utilities
+ Utility avoided costs (spreadsheet format)
+ Analysis of additional benefits suggested by TAC
+ Summary charts and figures

2.4 Task 4: Evaluate existing NEM programs

In Task 4, E3 proposes to evaluate existing NEM programs. To support this evaluation, E3 will develop a Microsoft Excel-based NEM Evaluation Model.

2.4.1 Input data

The primary inputs into this model will be data from the NEM systems database (Task 2) and calculated solar benefits (Task 3). Other key inputs to the model include:

+ **Utility retail rates** based on public tariffs, which will vary by utility
+ **Retail rate escalation** based on simple assumptions to be reviewed with the TAC
+ **Solar generation capacity factors and profiles** based on NREL's PVWatts calculator[7] or similar tools, which will vary by geographic region

2.4.2 Result metrics

The NEM Evaluation Model will develop a number of result metrics to illustrate the impacts of NEM programs on participants, non-participating ratepayers, and the full class of utility ratepayers. These metrics will include a set of standardized cost-effectiveness metrics from the Standard Practice Manual (SPM) as well as other metrics that describe participant and non-participant impacts in more plain terms. E3 proposes to include four SPM cost-effectiveness tests that reflect four different perspectives: participants (*i.e.*, customer solar adopters), non-participating ratepayers, all utility ratepayers, and society at large:

+ **Participant Cost Test (PCT)**
+ **Ratepayer Impact Measure (RIM)**
+ **Total Resource Cost test (TRC)**
+ **Societal Cost Test (SCT)**

[7] https://pvwatts.nrel.gov/pvwatts.php

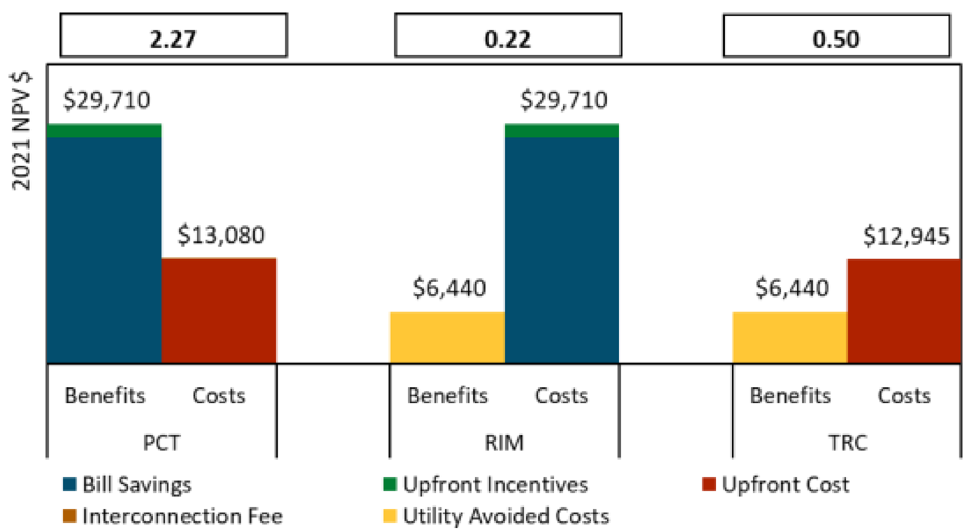
These cost tests describe lifecycle benefit-cost ratios calculated over the lifetime of a customer solar system. **Table 3** describes the benefits and costs that would factor into these cost tests.

Table 3: Four proposed cost-effectiveness tests based on the Standard Practice Manual

Participant Cost Test (PCT)		Ratepayer Impact Measure (RIM)	
Benefits	Costs	Benefits	Costs
• Bill savings • Incentives • Other private benefits	• Upfront Cost • Interconnection fee	• Utility avoided costs • Other ratepayer benefits	• Reduced utility revenues • Ratepayer-funded incentives
Total Resource Cost test (TRC)		**Societal Cost Test (SCT)**	
Benefits	Costs	Benefits	Costs
• Utility avoided costs • State and federal incentives • Other private benefits • Other ratepayer benefits	• Upfront costs	• Utility avoided costs • Other private benefits • Other ratepayer benefits • Other societal benefits	• Upfront costs, net of federal incentives

Figure 5 provides a recent E3 calculation of three cost-effectiveness tests for a customer solar system under California's NEM 2.0 tariff.

Figure 5: SPM cost tests calculated by E3 for a customer solar system under California's NEM 2.0 tariff. Numbers at top are benefit-cost ratios. [8]



[8] https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/zipped-files/2021-06-15-party-proposal-cost-effectiveness.zip

In addition to the lifecycle cost-effectiveness tests, E3 proposes to develop other metrics that provide more intuitive metrics focused on participating and non-participating ratepayers. Proposed participant metrics include:

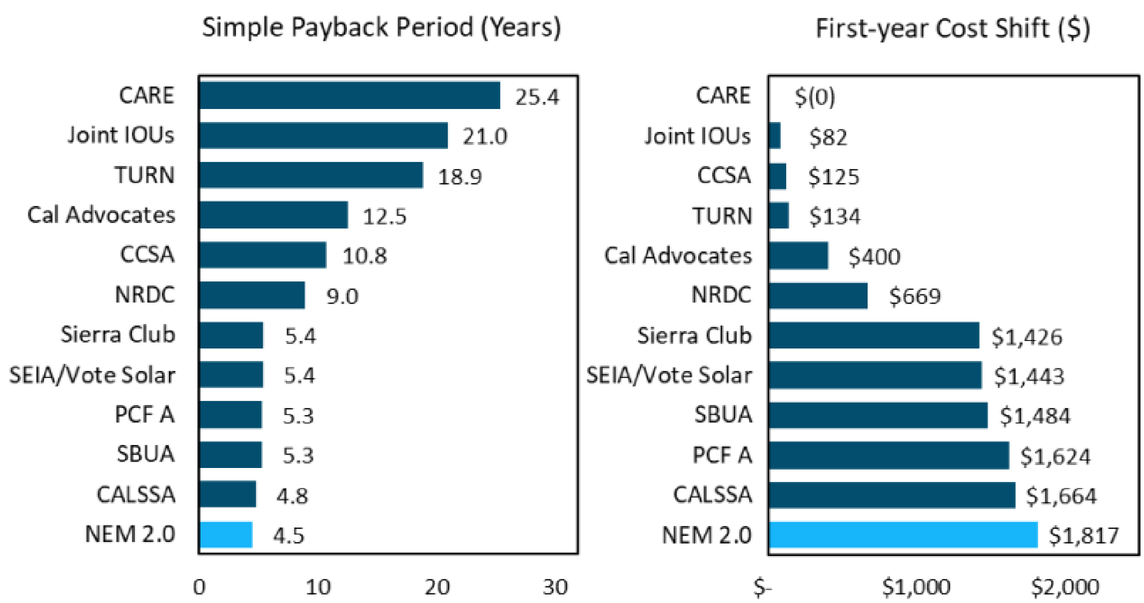
+ **Average solar compensation (c/kWh)** – Average customer bill savings for customer solar generation
+ **Simple payback period (years)** – Conservative; no rate escalation assumed
+ **Payback period (years)** – Assumes rate escalation

Proposed non-participant metrics include:

+ **Average solar avoided cost (c/kWh)** – Average system value of customer solar generation
+ **First-year cost shift ($/year)** – Difference between bill savings and avoided costs in first year of solar system operation, for an average customer solar system
+ **Lifetime cost shift ($)** – Simple sum over system lifetime, for an average customer solar system

In the CPUC's Net Energy Metering Revisit proceeding, stakeholders found these metrics useful as they are easy to understand and easy to communicate. In that proceeding, E3 calculated some of these metrics for successor tariff options proposed by different stakeholders, as shown in **Figure 6**.

Figure 6: Example metrics calculated by E3 in the CPUC NEM Revisit proceeding[9]



E3 proposes to calculate these metrics for each of the detailed study utilities. In addition, E3 will estimate how these metrics look on average for new solar systems installed in the state.

[9] https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/zipped-files/2021-06-15-party-proposal-cost-effectiveness.zip

2.4.3 Cost shift forecast

Assuming that NEM programs remain in place, E3 will develop two solar adoption forecasts and review them with the TAC. The two forecasts would be based on the following assumptions:

+ Assume that NEM capacity caps stay in place
+ Assume that NEM capacity caps are lifted

For each of these forecasts, E3 would estimate the total annual NEM cost shift ($/year) accounting for all interconnected NEM systems, as well as the total cumulative cost shift over time.

Task 4 Deliverables:

+ Microsoft Excel-based NEM Evaluation model
+ Summary charts and figures describing the above metrics

2.5 Task 5: Review tariff options for customer generation

In Task 5, E3 would provide a brief qualitative review of tariff options for customer generation that are being considered in other US jurisdictions. Broadly speaking, there are two different types of rate reform that can be used to reduce cost shifting associated with customer solar:

1. New tariffs for customer-generators. This option is most commonly thought of as "NEM Reform." Examples of new tariffs for customer-generators include New York's Value of DER (VDER),[10] California's Net Billing Tariff (NBT)[11], and Hawaii's Customer Grid Supply Plus.[12]
2. Cost-aligned default tariffs. While not commonly thought of as "NEM Reform," an alternative approach to reducing cost shifts from customer solar is to develop default residential tariffs with volumetric rates that are aligned with marginal costs. Under such a tariff, customer solar under NEM would be compensated at a rate that is aligned with the system value it provides. For example, California is developing rates with volumetric pricing that is more aligned with marginal costs in a new proceeding on Advanced Rate Design for Demand Flexibility.[13]

Task 5 Deliverables:

+ Memo for TAC to review
+ Section of final report

[10] https://www.nyserda.ny.gov/All-Programs/NY-Sun/Contractors/Value-of-Distributed-Energy-Resources
[11] https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/demand-side-management/net-energy-metering
[12] https://www.hawaiianelectric.com/products-and-services/customer-renewable-programs/rooftop-solar/net-energy-metering-plus/customer-grid-supply-plus
[13] https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-costs/demand-response-dr/demand-flexibility-rulemaking

2.6 Task 6: Final report

In this task, E3 will develop a public-facing report detailing the methodology and results of the study. The report will also detail the stakeholder engagement from this study and key feedback provided by the TAC. The intended audience for the report will be policymakers and regulators who may be familiar with existing NEM programs but are not experts in energy systems.

Utilities and the TAC will have an opportunity to review a draft report and provide feedback.

Task 6 Deliverables:

- Draft report for TAC to review
- Final report
- Public presentation on final report (webinar or in-person)

2.7 Task 7: Additional utilities for detailed study

At the client's request, additional utilities may be included for detailed study. Task 6 reflects the additional scope and budget associated with increasing the list of detailed study utilities beyond the four utilities in this proposal.

3 Project Budget

Table 4 describes the proposed project budget. E3 proposes to complete tasks 1-6 on a time and materials basis, not to exceed **$444,300**. In addition, E3 offers to evaluate additional utilities as "Detailed Study Utilities" at the client's request. The corresponding budget is reflected in Task 7, which would add **$40,000 per additional utility** to the total project budget. Due to time constraints, requests to include additional utilities must be received by July 1, 2023. Requests received after that date may not be possible to include in the modeling.

Table 4: Proposed project budget

Tasks 1-5 (Time and Materials)	Proposed Budget
Task 1: Technical Advisory Committee	$ 47,675
Task 2: NEM Systems Database	$ 87,950
Task 3: Evaluate Solar Benefits	$ 140,350
Task 4: NEM Evaluation	$ 93,000
Task 5: Review Tariff Options	$ 9,325
Task 6: Final Report	$ 66,000
Subtotal Tasks 1-6	**$ 444,300**
Task 7 (Time and Materials)	**Proposed Budget**
Task 7: Additional Utilities	$ 40,000 per additional utility
Subtotal Tasks 1-7	**$ 444,300 + $40,000 per additional utility**
Travel Expenses (Time and Materials)	**Proposed Budget**
Travel Expenses (at client's request)	$ 10,000 (estimated 4x trips for two E3 staff)

All project labor on these tasks will be billed by staff title using E3's standard hourly rates as provided in **Table 5**. These rates are valid for one year from contract execution. **Table 6** provides a detailed estimate of staff hours and budget by task for tasks 1-5.

Table 5: E3 Hourly Rates as of April 1, 2023.

Title	Rate ($/hr)
Founding Partner	$750
Managing Partner	$625
Senior Partner	$625
Partner	$575
Senior Director	$525
Director	$505
Associate Director	$475
Senior Managing Consultant	$440
Managing Consultant	$405
Senior Consultant	$360
Consultant	$295
Associate	$260
Analyst	$200

Table 6: Detailed project budget estimate by task. Tasks 1-6.

Staff	Title	Rate	Hours						
		$/hour	Task 1	Task 2	Task 3	Task 4	Task 5	Task 6	Total
			TAC Support	NEM Proj. Database	Solar Benefits	NEM Evaluation	Tariff Options	Report	
Arne Olson	Senior Partner	*$ 625*	10	5	10	10	5	15	***55***
Eric Cutter	Partner	*$ 575*	5		10			5	***20***
Ari Gold-Parker	Associate Director	*$ 475*	10	5	10	10	5	10	***50***
Christa Heavey	Associate Director	*$ 475*	20	10	20	20		10	***80***
Lindsay Bertrand	Managing Consultant	*$ 405*	20	20	100	40		40	***220***
Sierra Spencer	Managing Consultant	*$ 405*	40	80	20	60	5	20	***225***
Andrew Solfest	Senior Consultant	*$ 360*			100			20	***120***
Paul Picciano	Senior Consultant	*$ 360*		60		60	5	20	***145***
TBD	Consultant	*$ 295*			100			10	***110***
TBD	Associate	*$ 260*		60		40		10	***110***
	Total Hours by Task		105	240	370	240	20	160	***1,135***

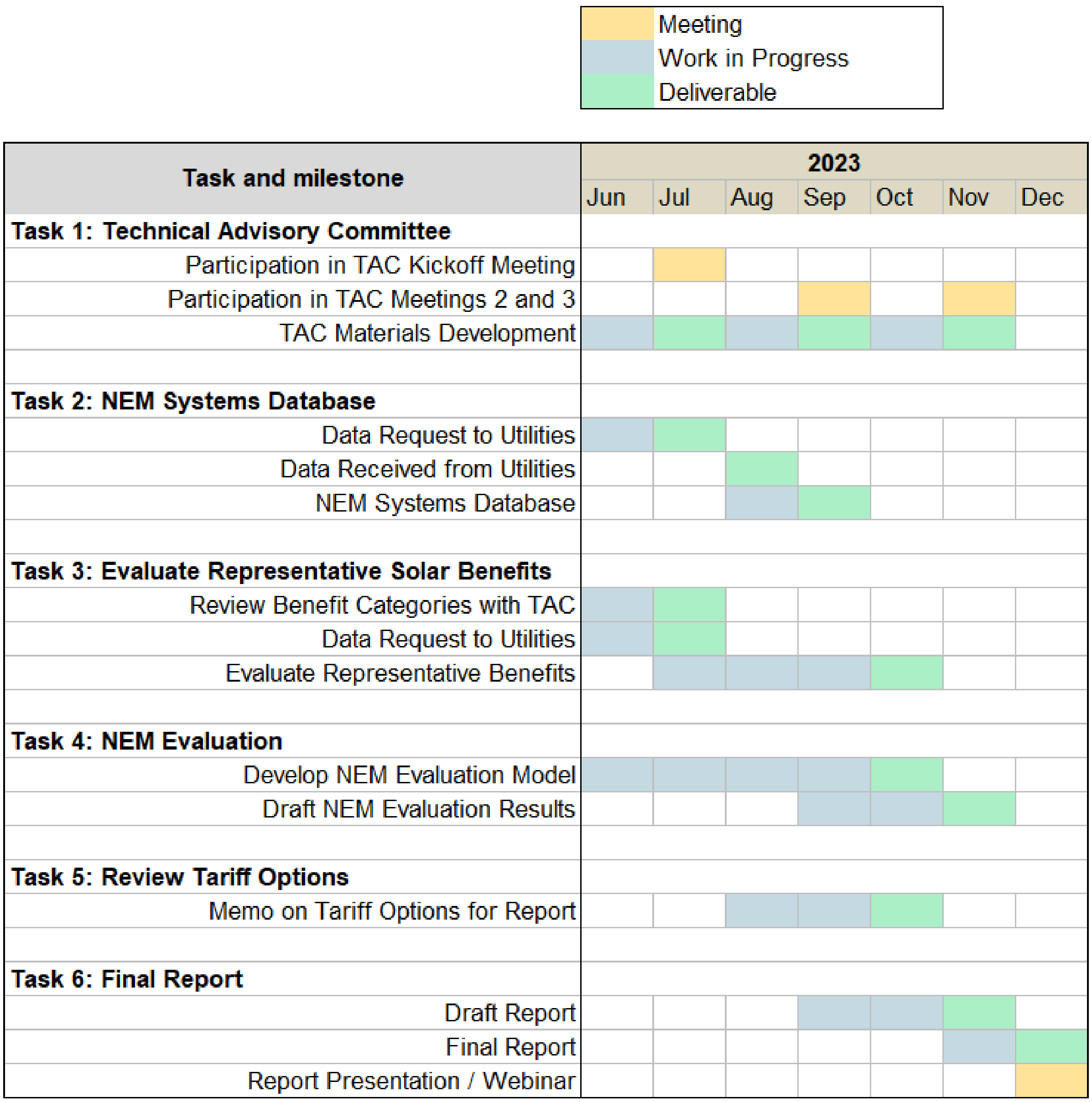
Staff	Title	Rate	Budget						
		$/hour	Task 1	Task 2	Task 3	Task 4	Task 5	Task 6	Total
			TAC Support	NEM Proj. Database	Solar Benefits	NEM Evaluation	Tariff Options	Report	
Arne Olson	Senior Partner	*$ 625*	$ 6,250	$ 3,125	$ 6,250	$ 6,250	$ 3,125	$ 9,375	***$ 34,375***
Eric Cutter	Partner	*$ 575*	$ 2,875	$ -	$ 5,750	$ -	$ -	$ 2,875	***$ 11,500***
Ari Gold-Parker	Associate Director	*$ 475*	$ 4,750	$ 2,375	$ 4,750	$ 4,750	$ 2,375	$ 4,750	***$ 23,750***
Christa Heavey	Associate Director	*$ 475*	$ 9,500	$ 4,750	$ 9,500	$ 9,500	$ -	$ 4,750	***$ 38,000***
Lindsay Bertrand	Managing Consultant	*$ 405*	$ 8,100	$ 8,100	$ 40,500	$ 16,200	$ -	$ 16,200	***$ 89,100***
Sierra Spencer	Managing Consultant	*$ 405*	$ 16,200	$ 32,400	$ 8,100	$ 24,300	$ 2,025	$ 8,100	***$ 91,125***
Andrew Solfest	Senior Consultant	*$ 360*	$ -	$ -	$ 36,000	$ -	$ -	$ 7,200	***$ 43,200***
Paul Picciano	Senior Consultant	*$ 360*	$ -	$ 21,600	$ -	$ 21,600	$ 1,800	$ 7,200	***$ 52,200***
TBD	Consultant	*$ 295*	$ -	$ -	$ 29,500	$ -	$ -	$ 2,950	***$ 32,450***
TBD	Associate	*$ 260*	$ -	$ 15,600	$ -	$ 10,400	$ -	$ 2,600	***$ 28,600***
	Total Budget by Task		$ 47,675	$ 87,950	$ 140,350	$ 93,000	$ 9,325	$ 66,000	***$ 444,300***

Finally, E3 is available to travel for key project events and milestones, such as TAC meetings and a presentation of the final report. Any travel would be initiated at the request of the client. Travel-related expenses would be incremental to project labor described above. **Table 4** includes an illustrative travel budget for four two-night visits to Washington State for two E3 staff members.

4 Project Schedule

Figure 7 provides a proposed schedule for project meetings and deliverables.

Figure 7: Proposed project schedule

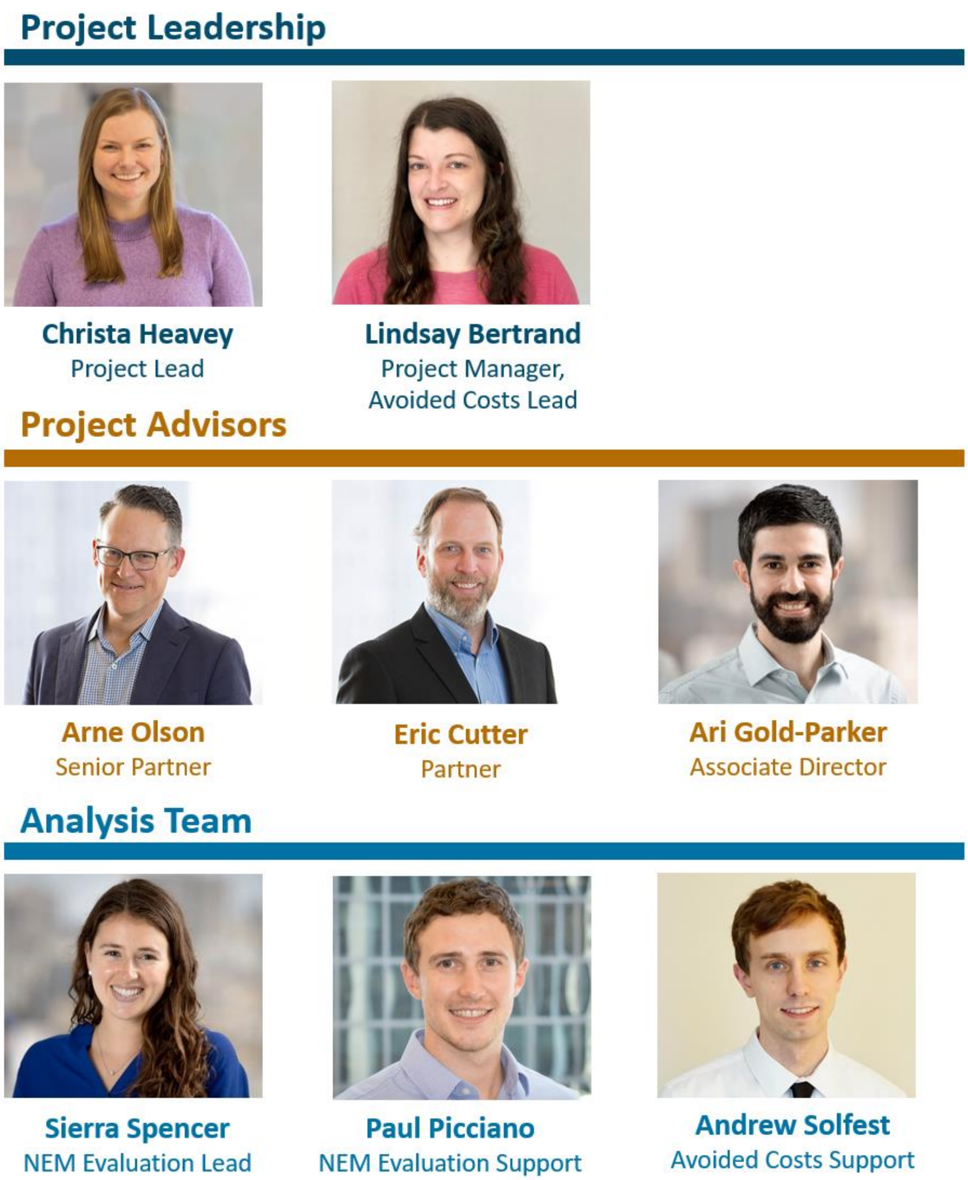


5 Project Team

5.1 Project Team

E3 has assembled a project team with experience in DER evaluation, avoided costs, and rate design. Other E3 staff members may also provide project support as needed. E3's project management style gives teams the freedom to create great products while also drawing on the support of the entire resource pool at E3, including our most senior experts. **Figure 8** shows E3's proposed project team, with team member bios provided in the following section.

Figure 8: E3 project team



5.2 Team Member Bios

Arne Olson, Senior Partner Mr. Olson leads E3's resource planning practice. Since joining E3 in 2002, he has led numerous analyses of how renewable energy and greenhouse gas policy goals could impact system operations, transmission, and energy markets. In 2013, he led the technical analysis and drafting of the landmark report *Investigating a Higher Renewable Portfolio Standard for California*, prepared for the five largest utilities in California. Since that time, he has overseen numerous studies of deeply decarbonized and highly renewable power systems in California, Hawaii, the Pacific Northwest, the Desert Southwest, New York, South Africa, and many other regions. Mr. Olson's clients have included most of the major utilities and market participants in the West, including the California Independent System Operator, Pacific Gas & Electric, Southern California Edison, Puget Sound Energy, PacifiCorp, Arizona Public Service, Sacramento Municipal Utilities District, Los Angeles Department of Water and Power, the Bonneville Power Administration, Calpine, NextEra, NRG, TransAlta and many others. He also works extensively with government agencies and industry organizations such as the California Public Utilities Commission, California Energy Commission, Oregon Public Utilities Commission, the Western Electric Coordinating Council, and the Western Interstate Energy Board. Mr. Olson earned an M.S. in International Energy Management and Policy from the University of Pennsylvania and the Institut Français du Pétrole, and bachelor's degrees in Statistics and Mathematical Sciences from the University of Washington.

Eric Cutter, Partner Mr. Cutter leads E3's practice area enabling distributed resources and electric vehicles to serve as valuable resources for the electric grid. He manages E3's team working on vehicle grid integration with utilities, regulators, automakers and electric vehicle service providers to develop strategic roadmaps, perform cost-benefit analysis and develop business strategies. Building on decades of experience in distributed resources, Mr. Cutter is also leading work on valuation of energy storage and flexible loads, with an emphasis on distribution planning. Prior to joining E3, he worked as an independent consultant in water resources for seven years, and at PG&E for ten years. Mr. Cutter graduated with an M.B.A. and M.S. in Energy and Resources from U.C. Berkeley, and bachelor's degrees in Economics and German from Tufts University.

Dr. Ari Gold-Parker, Associate Director Dr. Gold-Parker joined E3 in 2018 after completing his Ph.D. in Chemistry from Stanford University, where his doctoral research explored next-generation materials for solar cells. At E3, Dr. Gold-Parker supports E3's Climate Pathways and Distributed Energy Resources practice areas, where he works with policymakers, regulators, utilities, and businesses to understand how our electricity and natural gas systems will transform under deep decarbonization. His work focuses on building and vehicle electrification, utility cost recovery and rate design, and energy affordability. He has also enhanced E3's modeling capabilities by developing new tools for understanding the impacts of building electrification on peak electric loads and on natural gas revenue requirements and rates. Prior to completing his Ph.D. at Stanford, Dr. Gold-Parker earned a B.A. in Chemistry and Physics from Harvard University.

Christa Heavey, Associate Director Ms. Heavey's work focuses on the integration of distributed energy resources into the grid to support a clean energy future. Since joining E3 in 2019, Ms. Heavey has led work on transportation electrification for utilities, state agencies, and automakers to develop new programs, evaluate the impacts of electric vehicles on the grid, and determine the potential value of vehicle-grid integration. Ms. Heavey has also worked on utility rate design, regulatory filings, distributed solar, building electrification, and grid modernization. Ms. Heavey joined E3 from Pacific Gas & Electric Company, where she led regulatory and strategy work related to California's Low Carbon Fuel Standard, as well as data analytics on customer EV charging behaviors. She also completed clean energy fellowships at Natural Resources Defense Council and Union of Concerned Scientists. Ms. Heavey holds an M.S. in Civil and Environmental Engineering (Atmosphere/Energy) from Stanford University and a B.A. in Mathematics-Physics from Whitman College.

Lindsay Bertrand, Managing Consultant Ms. Bertrand, an experienced energy consultant with previous experience in energy efficiency consulting, renewable energy research, and engineering, joined E3 in 2022 and supports the DER group. Prior to E3, she was a consultant on the engineering team at Navigant Consulting (now Guidehouse), where she focused on energy efficiency program research, potential estimation, and evaluation activities for electric and gas utilities. Before working at Navigant, she was involved in building energy performance analyses at HOK, distributed photovoltaic research at Rocky Mountain Institute, and tidal powder feasibility studies at the National Renewable Energy Laboratory. Ms. Bertrand holds an M.S. degree in Civil and Environmental Engineering from Stanford University and a B.S. degree in Environmental Engineering from the University of Colorado at Boulder.

Sierra Spencer, Managing Consultant Ms. Spencer joined E3 in 2019 after completing her Master of Science in civil and environmental engineering from University of California, Berkeley. Her work focuses on analyzing opportunities to leverage distributed energy resources to reduce the environmental impacts of energy use and supporting clients' transportation electrification and renewables integration efforts. Prior to joining E3, Ms. Spencer conducted research on managed charging for electric vehicles and utilizing biofuels for central heating. In addition to her master's degree, Ms. Spencer received a B.S. in engineering and B.A. in environmental studies from Swarthmore College, where she was awarded a Presidential Sustainability Research Fellowship.

Andrew Solfest, Senior Consultant Andrew Solfest joined E3 in 2022 and supports E3's work in distributed energy resources and electrification. Andrew previously worked with Xcel Energy's energy efficiency and renewables team, administering Midwest community solar programs, coordinating project development, and helping institutional and residential customers achieve their clean energy goals. Prior to joining E3, Andrew completed an M.P.A. in Environmental Science and Policy at Columbia University, where he researched decarbonization pathways for the United States and developing nations.

Paul Picciano, Senior Consultant Mr. Picciano joined E3 in 2022 and primarily works in E3's resource planning group, where he evaluates clean electricity pathways for clients at the state, city, and utility levels. Mr. Picciano joined E3 after earning his master's degree from MIT's Technology and Policy Program where he utilized energy and air pollution models to evaluate air quality-related health and equity impacts of U.S. decarbonization policy. Prior to MIT, he worked for three years at Resources for the Future, where he developed and applied power sector models to analyze policies related to carbon pricing and clean energy standards at federal and state levels and engaged with decision makers and stakeholders to communicate their effects and advise policy development. Before that, he evaluated energy and environmental regulations at NERA Economic Consulting, and researched wind and solar energy integration at the National Oceanic and Atmospheric Administration. In addition to his M.S., Mr. Picciano earned a B.A. in Environmental Economics from Pomona College.

6 Relevant E3 Work

This section describes E3 work in relevant subject areas.

6.1 Value of Solar (and Storage)

Oregon Value of Solar (2016 – 2019). E3 was retained by Oregon Public Utilities Commission (PUC) staff to develop a methodology for calculating the Resource Value of Solar (RVOS) for Oregon's three investor-owned utilities. E3 provided expert testimony and produced a computer model for calculating RVOS on an area-and-time specific basis to calculate the value components of solar including energy, generation capacity, deferral of transmission and distribution investments, avoided Renewable Portfolio Standard compliance costs, avoided carbon emissions costs, real power losses, and avoided ancillary services costs. The Oregon PUC formally adopted E3's proposed methodology in January 2019 and ordered the utilities to use it to calculate RVOS values for their service areas in 2019. Expert testimony of Arne Olson is available at: http://edocs.puc.state.or.us/efdocs/HTB/um1716htb101623.pdf

SMUD Value of Solar and Solar+Storage Study (2020). Sacramento Municipal Utility District (SMUD) selected E3 in 2020 to prepare a study of the value of customer solar and solar plus storage facilities in scenarios that are consistent with SMUD's long-term carbon goals. E3 subsequently worked with SMUD to quantify the impacts of a variety of rate design options on the economics of customer solar adoption as well as their ability to ameliorate the cost shifting associated with SMUD's existing Net Energy Metering program. The study is available here:
https://www.smud.org/-/media/Documents/Rate-Information/2022-2023-Rate-Action/VOSstudy.ashx

California Public Utilities Commission, Net Energy Metering Revisit Rulemaking Technical Support (2020-present). E3 supported the California Public Utilities Commission (CPUC) in the development of the Net Billing Tariff, the successor to the Net Energy Metering 2.0 (NEM) tariff. Pursuant to CA Assembly Bill 327 (2013, Perea), the successor tariff must balance the objectives of maintaining the growth of distributed generation and ensuring that the benefits to NEM participants are not outweighed by the costs to nonparticipants. In this proceeding, E3 worked with Verdant Associates to develop the NEM 2.0 Lookback Study, which evaluated the impacts of the existing "NEM 2.0" tariff on participants and nonparticipants. Next, E3 developed a White Paper on Successor Tariff Options for the proceeding. After parties submitted their own proposals for tariff designs, E3 developed an Excel model to estimate the impact of these tariffs of participant and nonparticipants and summarized the results in a report on Party Proposal Cost-effectiveness. E3 has also provided technical modeling for the Commission's December 2021 proposed decision and the November 2022 proposed decision. The 2022 proposed decision was adopted by the Commission as D.22-12-056.

New York Value of Distributed Energy Resources Proceeding Support (2016 – Present). E3 has been supporting the Value of DER (VDER) proceeding in New York since its inception on many different tasks. We work with a senior-level NYSERDA and DPS project team to support the VDER Proceeding by providing analytical services and strategic advice with regards to how to calculate the benefits and costs of various types of DERs such as NEM eligible solar PV and community distributed generation. We are also analyzing the financing and revenue certainty requirements necessary for certain DERs to be bankable and viable from the project development standpoint especially with regards to low-moderate income installations. We have authored reports for different rate design formulations (see our Full Value Tariff Report) as well as completing the development of a VDER Calculator. The VDER Calculator is a publicly available Excel-based tool designed to help developers and other entities understand and quantify each value stream available to solar and solar plus storage projects under the Phase One and Phase Two Value Stack tariffs. The tool contains detailed information and model logic related to different project types, including CDG projects, and the available compensation streams for each project type by utility territory. We have also analyzed and reviewed how to calculate utility distribution value and how to translate it to determine impacts and potential DER value. Additionally, we recently worked with DPS to evaluate and analyze different rate design choices for mass market customers that have historically been eligible for NEM. This analysis included an examination of the impacts on solar customers as well as the bill impacts for other technologies, such as solar plus storage, standalone storage, heat pumps, and electric vehicles.

Nevada NEM Update (2016). E3 updated a 2014 report for the Public Utility Commission of Nevada (PUCN) that calculated the cost-effectiveness of solar PV net energy metering (NEM) systems in Nevada from all five Standard Practice Manual perspectives: participant, non-participating ratepayer, program administrator, Nevada, and society. In contrast to the prior report, which found a small net benefit to non-participating ratepayers, E3's 2016 analysis found a cost-shift of $0.04/kWh for future solar NEM systems. This finding was largely due to the decline in both natural gas prices and utility-scale solar prices, both of which affect the avoided cost of solar NEM systems. E3's study, published in August 2016, received media coverage including an article in Greentech Media. Publicly available report available at: http://puc.nv.gov/uploadedFiles/pucnvgov/Content/About/Media_Outreach/Announcements/Announcements/NetMeteringStudy2016.pdf

6.2 Avoided Costs

CPUC Avoided Cost Methodology and "E3 Calculator" (2003-Present). E3 developed the CPUC's officially adopted methodology for determining the cost effectiveness of investor-owned utility energy efficiency programs. The methodology is based on an avoided cost methodology in combination with long-term forecasts of electric and gas avoided costs. E3's methodology produces avoided cost estimates that are transparent and are easily and regularly updated. In use since 2004, E3's Avoided Cost Model (ACM) has evolved along with energy markets and policy in the West, as well as the needs of the CPUC. Since 2019, E3 has provided ongoing support to refine the CPUC's cost-effectiveness framework for distributed energy resources, expanding the applications of the Avoided Cost Calculator to include the cost-effectiveness of California's entire DER portfolio. The Avoided Cost Calculator currently projects avoided costs for energy, losses, generation capacity, ancillary services, subtransmission and distribution capacity, renewable portfolio standard purchases, carbon allowances, and other air permit costs.

E3's initial methodology was developed as part of a public rulemaking process involving fourteen external parties that included stakeholders from the California investor-owned utilities, The Utility Reform Network, Natural Resources Defense Council, and California Large Energy Consumers Association. The "E3 Calculator," now called the "Avoided Cost Calculator," remains in use almost 20 years later for all California IOUs to report on their energy efficiency programs. The 2022 Avoided Cost Calculator and Documentation are available here:

https://e3.sharefile.com/share/view/s3fdd4ff8b9db4e95904726427ae54e81/fo1ed759-f5d6-4904-8047-9aa67a677f9a

Portland General Electric (PGE), DER Cost-Effectiveness Framework (2022). E3 is supporting PGE to advance cost-benefit analysis for DERs, improve valuation of DERs, and support key strategic decision making at the company regarding impacts on rates, competitiveness, and electrification policy. E3 will help PGE align DER cost-benefit evaluation with Integrated Resource Planning, expand and improve the range of grid, host and societal benefits considered, balance environmental justice objectives with goals for energy affordability and competitive rates and to advance electrification policy.

Sacramento Municipal Utility District DER Cost Effectiveness Tool (2018 – Present). E3 created a tool for the Sacramento Municipal Utility District (SMUD) that allows for evaluation of the cost effectiveness and emissions impacts of various DER measures. The outputs of SMUD's IRP process are used as inputs and define the underlying utility system, which serves as a baseline against which to evaluate the net benefits of potential DER programs including electric vehicles, building electrification, and energy efficiency. Linking the supply and demand sides in this fashion allows for hourly assessment of the costs and benefits associated with a given DER measure, including accounting for the hourly emissions impacts of different load modifications. This tool considers several different IRP scenarios, describing varying levels of assumed decarbonization of California's electric grid.

Multiple Utilities, Marginal Cost Studies (2019 - present). E3 has decades of experience assisting utilities in traditional cost-of-service analysis and retail rate design. As more customers seek to manage their energy bills through behind-the-meter solar generation, energy storage, and load management applications, E3 is helping clients devise tariffs that promote investments in distributed resources and reflect cost causation and equity principles. We also work with utilities, electric vehicle service providers, and automakers to design rates that promote transport electrification while ensuring cost-effective grid integration of electric vehicles and full recovery of utility costs. Examples of E3's recent projects include the development of marginal distribution cost study for Central Maine Power Company and marginal cost studies for the Avangrid utilities in New York.

6.3 Rate Design

California Public Utilities Commission Income-Based Fixed Charge Model (2022-present). E3 is supporting the California Public Utilities Commission (CPUC) in an active proceeding to make major updates to default residential electric rates for California's large investor-owned utilities. Assembly Bill 205 (2022) requires the CPUC to established income-graduated fixed charges in default residential rates, authorized no later than 2024. E3 has developed a public Excel-based model to support stakeholders in developing revenue-neutral fixed charge designs and to facilitate comparison among party proposals. E3 and the CPUC are currently accepting feedback on the draft model, which is available here: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/demand-response/demand-response-workshops/advanced-der---demand-flexibility-management/fixed-charge-design-model-20230210.xlsb

AltaLink Transmission Rate Design (2017). E3 was retained by AltaLink to assess the existing AESO transmission tariff and whether changes were needed in light of escalating rates to better adhere to key rate design principles. Significant increases in the coincident peak (CP) charge were leading to an incentive for uneconomic bypass of the transmission system via distributed generation. E3 presented the findings at several AESO transmission tariff workshops, including alternative rate design proposals that tied the compensation for CP reduction to the avoided cost of transmission.

Pacific Northwest Public Utility District (PUD) New Large Load Analysis (2018). E3 was engaged by a PUD in the Pacific Northwest to analyze potential impacts from new large loads in its service territory and to recommend mitigation approaches. After analyzing existing contracts and related policies, E3 quantified prospective impacts of new large loads on future cost of service and margins as well as uses for the margin generated from new large users. E3 also explored desired utility growth levels and performed scenario analysis to understand expected utility outcomes under a range of future regulatory and economic scenarios that could lead to new large load departures. Key issues in this analysis included institutional risk from new large loads and how it may vary over time; how operating costs and margin should be allocated to new large loads; and what level of large user credit security should be established. E3 presented its findings to the PUD Board of Directors.

Full Value Tariff Design and Retail Rate Choices under New York's Reforming the Energy Vision (2015-2016). E3 worked with a senior level NYSERDA (New York State Energy and Research Development Authority) and DPS (Department of Public Service) project team to perform a study examining retail rate choices and the formulation of a "full value" tariff that among other things can compensate DERs at levels more reflective of their value. The study directly built upon the REV Track 2 Department of Public Service Staff white paper. The study was released on April 20, 2016 in the Value of DER proceeding and it presents a number of choices and options when examining the creation of a conceptual, but implementable full value tariff (FVT) with illustrative rate levels based on utility filings and sound economic principles to achieve the following goals: 1) to more accurately compensate customer and third party contributions to managing the grid; 2) to collect utility embedded costs equitably and efficiently; 3) to increase competition for distribution services; and, 4) to lower customer costs through more efficient use of the distribution system. The project report and technical appendix along with multiple internal client presentations and working documents are available at:
http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={A0BF2F42-82A1-4ED0-AE6D-D7E38F8D655D}

Fortis Alberta – Distributed Energy Resources Integration Roadmap (2020). E3 was retained by Fortis Alberta to provide expert testimony in the Alberta Utilities Commission's (AUC) Distribution Inquiry. E3's testimony provided a specific and actionable roadmap for the integration of distributed energy resources (DERs) of all technologies and outlined that the challenges of DER integration will be unique to each jurisdiction based on consumer choice, market design, and technological advancement. E3 provided six potential distribution system business models that would allow for the integration of DERs along with key changes to rate design and market access that would facilitate a successful transition. Expert witness testimony of Ren Orans is available here:
https://www.ethree.com/wp-content/uploads/2022/01/Testimony-to-Alberta-Utilities-Commission-on-Fortis-Alberta-DER-Roadmap.pdf

UTILITY ADVISORY COMMITTEE AGENDA ITEM COVERSHEET

Meeting Date: 7/11/2023 Agenda Category: Items of Business

Prepared By: Clint Whitney, Energy Services Director

Subject:
PURPA 111d Requirements to Consider Additional Demand Response (DR) and Electric Vehicle (EV) Charging Programs

Department:
Energy Services

Recommended Motion:

Summary:
The 2021 Infrastrustructure Investment and Jobs Act updated Public Utilities Regulatory Policy Act (PURPA) 111d and requires non-regulated cooperatives, utilities, and state-regulated utilities to consider adopting standards for promoting greater transportation electrification (Section 40431) and utility demand response (Section 40104). To meet the new procedural requirements, the City will need to provide a public notice, hold an equivalent of a hearing, and make a determination by November 15, 2023 of either declining or deciding to implement considerations.

The City has already identified elements of Demand Response (DR) in the City's Clean Energy Implementation Plan (CEIP) that was presented to UAC and approved by City Council on October 19, 2021 through Resolution #123-21. In 2023, the City also began promoting an electric vehicle (EV) charger rebate for residential customers.

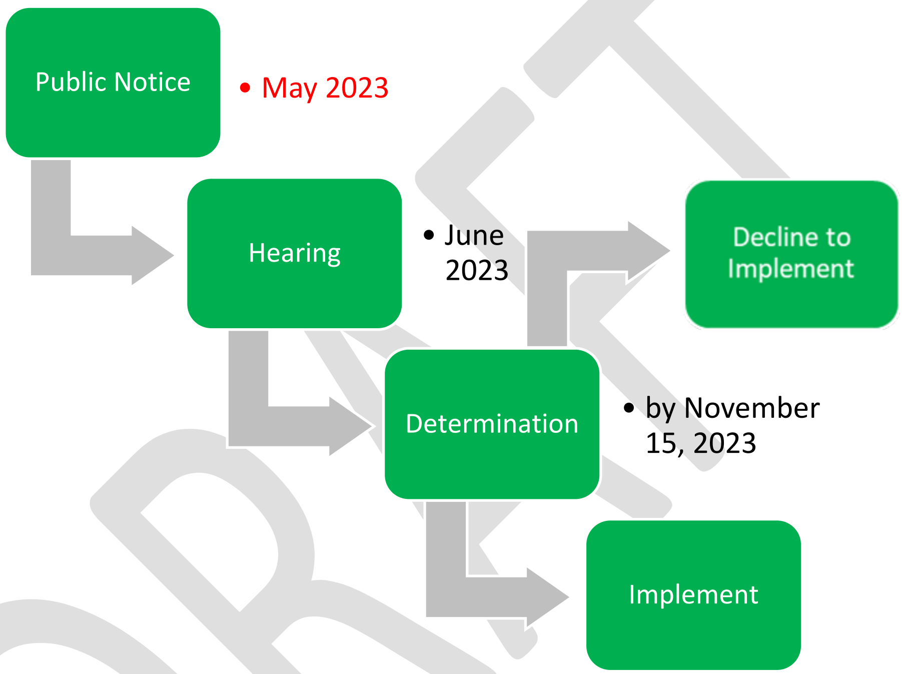
Should the City consider elements of DR or EV beyond what has already been presented, approved, and implemented?

Fiscal Impact:
No additional fiscal impact at this time.

Attachments:
1. 2022 10 PURPA Outline

PURPA – Public Utility Regulatory Policies Act of 1978

- Amended in 2021 through the IIJA "Jobs Act"
- BBEC "shall consider" these new standards (since retail sales are over 500,000,000 kWh)
  - Demand Response – Promote the use of demand-response and demand flexibility practices by commercial, residential, and industrial consumer to reduce electricity consumption during periods of unusually high demand.
  - Electrical Vehicle Charging Programs – Promote greater electrification of the transportation sector, including rate establishment
- Procedural Requirements



  - Public Notice – Provide information about the meeting 10 - 50 days before the meeting through posts on the website (as directed by the board president)
  - Hearing –
    - Present written findings
    - Allowing oral and written public comment
  - Determination –
    - In writing and publicly available
    - Based upon (1) Findings and (2) Evidence presented at the hearing (Existing Standards that are similar or relate to new proposed standards, Range of options considered, Options under Cooperative's control or not)
    - If declining to adopt (other than it is covered by existing standards), provide reasoning
    - If pointing to existing *practices*, list "specific steps" where there is consistency with the standard OR list existing/pending steps that "achieve the same objectives" – i.e. WA State standard or regulation
    - Recommend a Board Resolution (before November 2023) to document process

New PURPA 111(d) Standards Under IIJA

Demand-Response Practices

(A) In General – Each electric utility shall promote the use of demand-response and demand flexibility practices by commercial, residential, and industrial consumers to reduce electricity consumption during periods of unusually high demand.

(B) Rate Recovery

(i) In General – Each State regulatory authority shall consider establishing rate mechanisms allowing an electric utility with respect to which the State regulatory authority has ratemaking authority to timely recover the costs of promoting demand-response and demand flexibility practices in accordance with subparagraph (A).

(ii) Nonregulated Electric Utilities – A nonregulated electric utility may establish rate mechanisms for the timely recovery of the costs of promoting demand-response and demand flexibility practices in accordance with subparagraph (A).

NRECA America's Electric Cooperatives

View the codified text here:
https://www.law.cornell.edu/uscode/text/16/2621

New PURPA 111(d) Standards Under IIJA

Electric vehicle charging programs

Each State shall consider measures to promote greater electrification of the transportation sector, including the establishment of rates that—

(A) promote affordable and equitable electric vehicle charging options for residential, commercial, and public electric vehicle charging infrastructure;

(B) improve the customer experience associated with electric vehicle charging, including by reducing charging times for light-, medium-, and heavy-duty vehicles;

(C) accelerate third-party investment in electric vehicle charging for light-, medium-, and heavy-duty vehicles; and

(D) appropriately recover the marginal costs of delivering electricity to electric vehicles and electric vehicle charging infrastructure.

NRECA America's Electric Cooperatives

View the codified text here:
https://www.law.cornell.edu/uscode/text/16/2621

UTILITY ADVISORY COMMITTEE AGENDA ITEM COVERSHEET

Meeting Date: 7/11/2023 Agenda Category: Other Informational Items

Prepared By: Clint Whitney, Energy Services Director

Subject:
Capital Work Plan Update - May 2023

Department:
Energy Services

Recommended Motion:
No action needed.

Summary:
The 2023 Capital Work Plan (CWP) has an approved budget of $11.1M. The CWP significant areas of capital work include: Advanced Metering Infrastructure (AMI), System Improvements, Renewal & Replacements, Substation Improvements, and Line Extensions. Capital plans are influenced by reliability data and areas of economic development. Capital work is funded from electric rate revenue and revenue bonds. Attached is a summary of the 2023 CWP through May.

While CWP expenditures through May are 12% of the approved budget, the 2023 CWP is planned with more expenditures in the second half of the year associated with the construction of City View Bank #2 addition. The CWP does not reflect significant expenditures like the delivery of the substation power transformer in June for City View Substation or the recent completion of Westview Acres renewal and replacement work. The support of line extensions to new developments or construction is approximately 1/3 of the yearly expected work and which aligns with a substantial slow down in residential and commercial construction permit applications.

Capital investments maintain and improve electrical distribution infrastructure to ensure continued support for reliable electric service, economic development, and a safe system while balancing costs.

Fiscal Impact:
There is no fiscal impact.

Attachments:
1. RES CWP REPORT-May 2023

Richland Energy Services

Capital Work Plan

May 2023

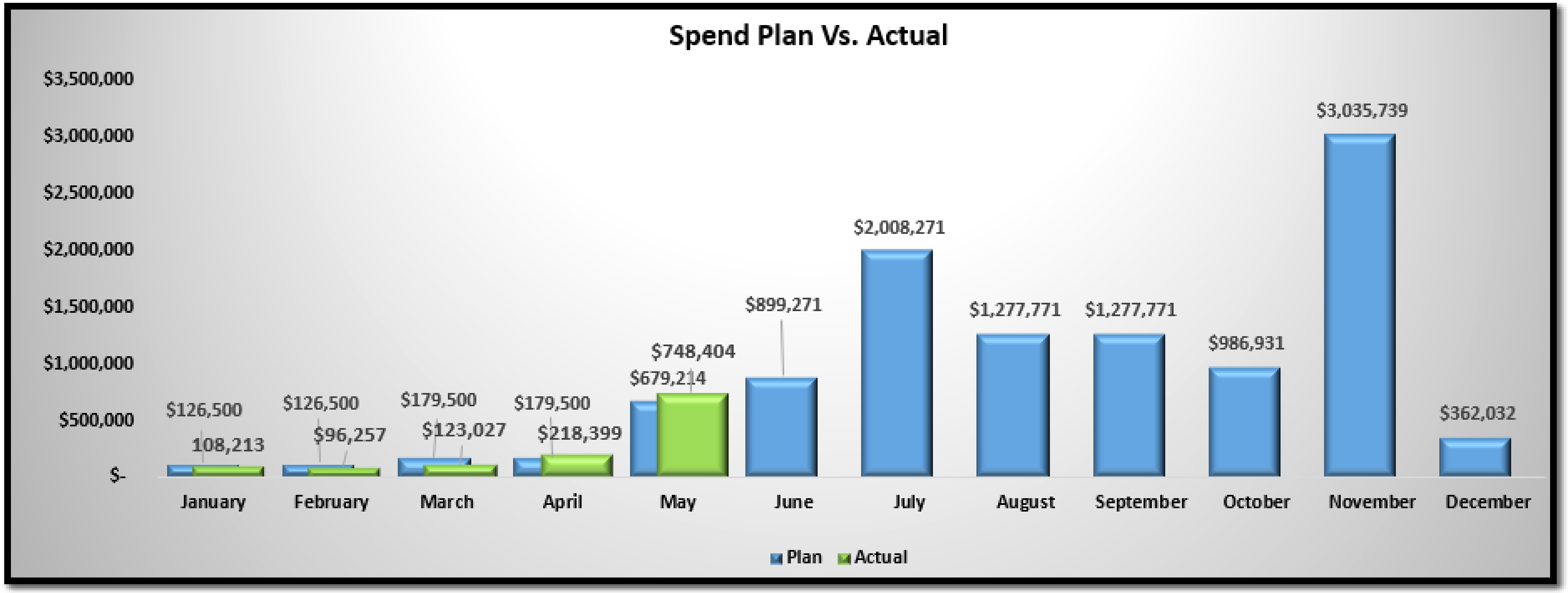
CWP Costs for May

	Approved 2023 Budget	2023 Estimated Costs	Actual	Remaining	May
Line Extensions	$2,120,000	$ 2,120,000	$ 702,686	$ 1,417,314	$ 579,006
System Improvements	$1,028,000	$ 1,028,000	$ 329,883	$ 698,117	$ 68,202
Renewal and Replacement	$2,562,000	$ 2,562,000	$ 210,564	$ 2,351,436	$ 99,518
Purchase Southwest Service Area Infrastructure	$212,000	$ 212,000	$ -	$ 212,000	$ -
Substation Improvements	$5,217,000	$ 5,217,000	$ 51,168	$ 5,165,832	$ 1,678
Grand Total	$11,139,000	$ 11,139,000	$ 1,294,301	$ 9,844,699	$748,404

Cost Performance YTD:	$1,294,301
Cost Performance remaining:	$9,844,699
YTD % Complete	12%

CITY OF RICHLAND WASHINGTON

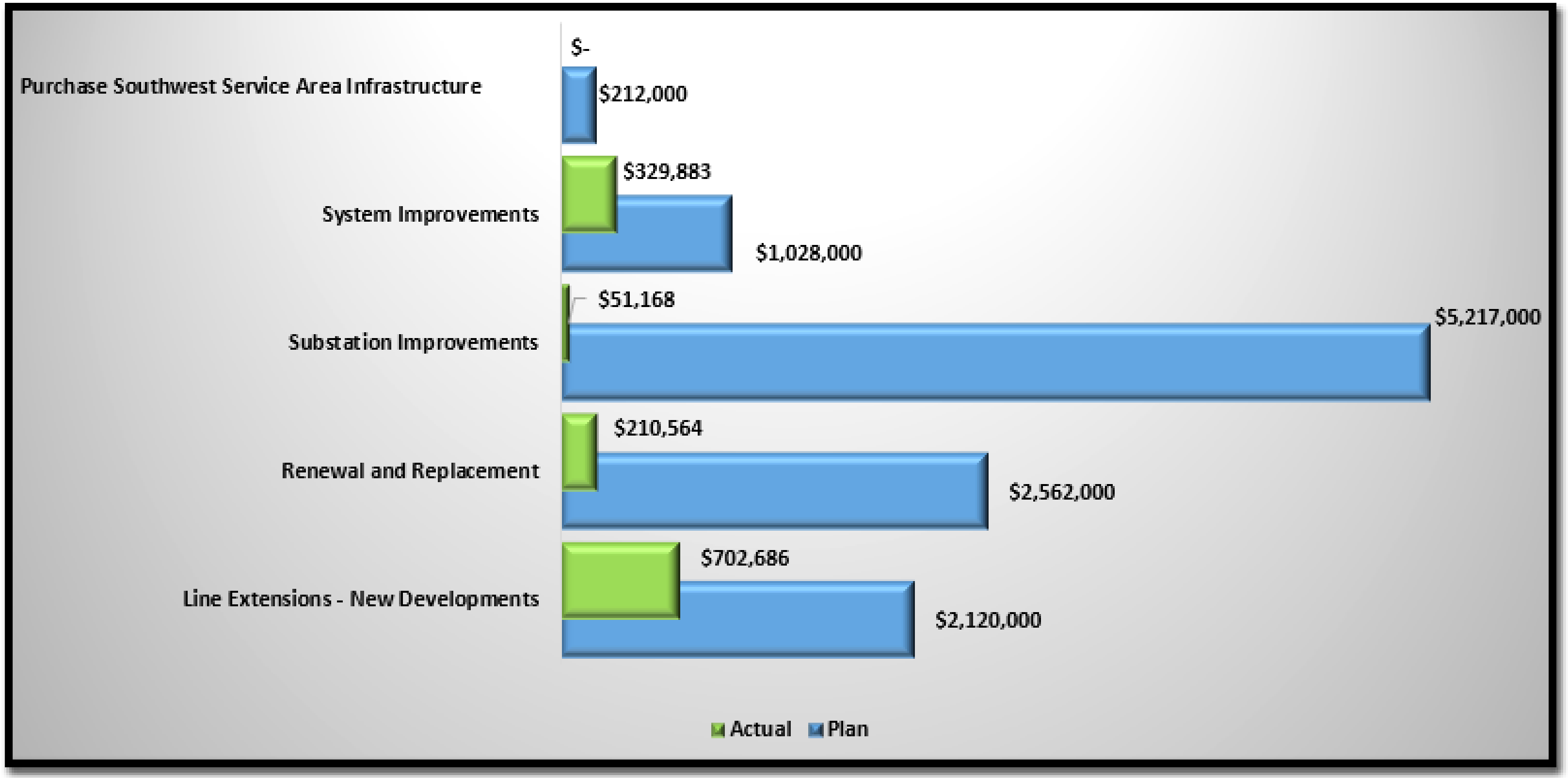
CWP Monthly Spend Vs. Actuals



% Complete of Overall Spend Plan		
To-Date Projected	$	1,291,214
To-Date Actual	$	1,294,301
Variance	$3,087	100%

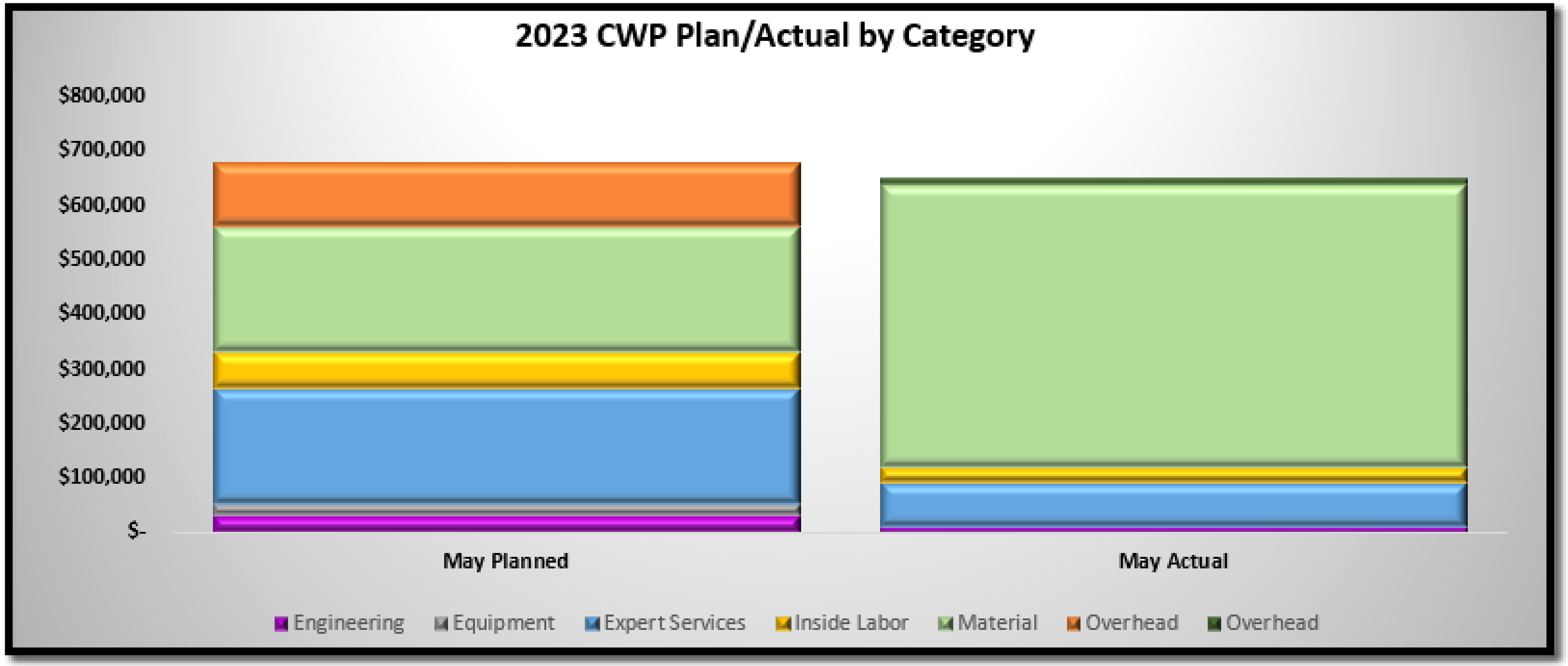
CITY OF RICHLAND
WASHINGTON

Costs by Category



CITY OF RICHLAND
WASHINGTON

CWP Cost Types



Cost Type	May Planned	May Actual
Engineering	$ 32,768	$ 9,966
Equipment	$ 21,712	$ -
Expert Service	$ 213,239	$ 178,907
Inside Labor	$ 66,384	$ 28,147
Material	$ 230,763	$ 519,833
Overhead	$ 114,348	$ 11,551
Total	**$ 679,214**	**$ 748,404**

CWP Project Costs for May

	Approved 2023 Budget	2023 Estimated Costs	Actual	Remaining	May
Line Extensions	**$2,120,000**	**$ 2,120,000**	**$ 702,686**	**$ 1,417,314**	**$ 579,006**
System Improvements	**$1,028,000**	**$ 1,028,000**	**$ 329,883**	**$ 698,117**	**$ 68,202**
System Improvements					
METER INSTALLATION MATERIALS	$0	$ -	$ 160,883	$ (160,883)	$36,834.28
NEW & ALT SVCS - UNDERGROUND	$498,000	$ 498,000	$ 107,665	$ 390,335	$25,324.33
RES OH UG ENG DESIGN DWGS	$0	$ -	$ 8,538	$ (8,538)	$1,858.85
SKYLINE DR DEVELOPMENT; NEW PRIMARY AND SECONDARY	$0	$ -	$ 9,643	$ (9,643)	$0.00
Fusion Substation Transmission Line	$530,000	$ 530,000	$ -	$ 530,000	$0.00
Constuction Assembly Standards	$0	$ -	$ 20,808	$ (20,808)	$3,797.95
1663 Fowler, Relocate Aprox 550ft 3 750MCM out of easement	$0	$ -	$ 19,941	$ (19,941)	$0.00
Substation PLC Replacement (Sandhill Crane, City View, and F	$0	$ -	$ 2,406	$ (2,406)	$386.54
Renewal and Replacement	**$2,562,000**	**$ 2,562,000**	**$ 210,564**	**$ 2,351,436**	**$ 99,518**
First Street Re-Gasket	$0	$ -	$ 330	$ (330)	$0.00
1902 Airport Way, Renew Replace Boring Contract Richland Ai	$1,916,000	$ 1,916,000	$ 2,372	$ 1,913,628	$151.59
2500 GWW, R and R UG Prim for Apt complex, ILLAHEE Apts, 20	$0	$ -	$ 207,862	$ (207,862)	$99,366.54
Purchase Southwest Service Area Infrastructure	**$212,000**	**$ 212,000**	**$ -**	**$ 212,000**	**$ -**
Substation Improvements	**$5,217,000**	**$ 5,217,000**	**$ 51,168**	**$ 5,165,832**	**$ 1,678**
Demand Response by Voltage Reduction (DR by VR)	$0	$ -	$ 630	$ (630)	$0.00
Gateway Substation 2021 Project	$0	$ -	$ 3,666	$ (3,666)	$196.52
City View Bank 2 Addition	$4,293,000	$ 4,293,000	$ 45,955	$ 4,247,045	$1,329.71
Stevens/Thayer Rebuild Design	$636,000	$ 636,000	$ -	$ 636,000	$0.00
City View Extension 131, EXT 3P 750 Aprox 2000ft from Cityvie	$288,000	$ 288,000	$ 918	$ 287,082	$151.59
Grand Total	**$11,139,000**	**$ 11,139,000**	**$ 1,294,301**	**$ 9,844,699**	**$748,404**

UTILITY ADVISORY COMMITTEE AGENDA ITEM COVERSHEET

Meeting Date: 7/11/2023 Agenda Category: Other Informational Items

Prepared By: Clint Whitney, Energy Services Director

Subject:
Draft Capital Improvement Projects for 2024-2030

Department:
Energy Services

Recommended Motion:
No action required.

Summary:
Using data from existing reliability metrics, outage information, and economic development areas, Energy Services staff has drafted a list of Capital Improvement Projects (CIP) for the 2024-2030 period in the attached file.

The near term 2024-2026 annual CIP recommendations range from $10.7M to $12.0M with significant projects including:

- 2024 - Stevens Substation Bank 1 Rebuild, $4.8M
- 2025 - Thayer Subtation Bank 1 Rebuild, $4.2M
- 2026 - Sandill Substation Bank 3 Addition, $5,9M
- 2024-2030 - Pole Replacement Program, $600k annually
- 2024 - Bypass Highway Overhead Relocation, $1.6M
- 2024-2026 - Underground Cable Replacement, $1.9M, $4.1M, $2.1M respectively
- 2026 - Dallas Road Substation Design, $600k

Each year, as project certainty and need increases, elements of the CIP recommendations would be included in the budget for the Council's consideration and approval. Renewal & Replacement projects and Development Line Extensions have less year to year certainty than substation additions and rebuild projects.

Fiscal Impact:
Elements of the Capital Improvement Projects is planned to be included in staff's budget recommendation for the Council's annual budget consideration and approval.

Attachments:
1. Draft Capital Improvement Projects for 2024-2030

TOTAL UTILITY: ALL BUDGETED PROJECTS

TYPE	2024	2025	2026	2027	2028	2029	2030
MAT'L	$4,753,000	$4,573,000	$4,783,800	$8,144,600	$4,571,800	$4,273,000	$3,800,000
XPRT SRVS	$3,830,000	$4,250,000	$4,290,000	$6,444,000	$5,109,000	$3,709,000	$2,834,000
INSIDE LABOR	$595,000	$540,000	$675,200	$817,400	$655,200	$540,000	$440,000
EQUIP	$178,000	$178,000	$178,000	$219,000	$211,000	$178,000	$139,000
OH	$722,000	$680,000	$1,439,000	$1,557,000	$635,000	$542,000	$433,000
ENGR'NG	$602,000	$613,000	$681,000	$1,030,000	$670,001	$554,002	$219,003
GRAND TOTAL	**$10,680,000**	**$10,834,000**	**$12,047,000**	**$18,212,000**	**$11,852,001**	**$9,796,002**	**$7,865,003**

CIP CATEGORY	CIP Project #		2024	2025	2026	2027	2028	2029	2030
NEW	TBD	TOTAL	$0	$0	$0	$0	$0	$0	$0
EQUIPMENT STORAGE/MAINTENANCE REPAIR SHOP	ES130012	TOTAL	$0	$0	$0	$0	$0	$0	$0
SOUTHWEST SERVICE AREA INFRASTRUCTURE ACQUISTION	ES130009	TOTAL	$0	$0	$0	$0	$1	$2	$3
SYSTEM IMPROVEMENTS	ES130011	TOTAL	$593,000	$473,000	$784,000	$580,000	$792,000	$473,000	$0
RENEWAL & REPLACEMENT	ES130010	TOTAL	$4,217,000	$4,753,000	$2,765,000	$2,892,000	$2,765,000	$2,765,000	$2,740,000
ADVANCED METERING INFRASTRUCTURE UTILITIES PROJECT	ES130005	TOTAL	$0	$0	$0	$0	$0	$0	$0
SUBSTATION IMPROVEMENTS	ES130007	TOTAL	$4,887,000	$4,824,000	$6,522,000	$5,774,000	$699,000	$5,840,000	$4,407,000
DALLAS RD AREA IMPROVEMENTS (FORMERLY DALLAS RD SUB)	ES130001	TOTAL	$0	$0	$583,000	$7,159,000	$0	$0	$0
LESLIE RD SUBSTATION (FORMERLY BADGER SUBSTATION)	ES130004	TOTAL	$0	$0	$0	$0	$0	$0	$0
HANFORD SUBSTATION (moved to 2023)	ES130002	TOTAL	$0	$0	$0	$583,000	$6,625,000	$0	$0
GATEWAY SUBSTATION: HORN RAPIDS INDUSTRIAL AREA - DESIGN AND CONSTRUCTION	ES130003	TOTAL	$0	$0	$675,000	$506,000	$253,000	$0	$0
LINE EXTENSIONS - NEW DEVELOPMENTS	ES130008	TOTAL	$983,000	$784,000	$718,000	$718,000	$718,000	$718,000	$718,000
		GRAND TOTAL	**$10,680,000**	**$10,834,000**	**$12,047,000**	**$18,212,000**	**$11,852,001**	**$9,796,002**	**$7,865,003**

2024	2025	2026	2027	2028	2029	2030
1.27	1.30	1.33	1.36	1.39	1.42	1.45
0.25	0.25	0.25	0.25	0.25	0.25	0.25
0.53	0.53	0.53	0.53	0.53	0.53	0.53
0.06	0.06	0.06	0.06	0.06	0.06	0.06

Note: Needs to be completed (NEEDS TO BE UPDATED)

FOOTNOTES:

1) Residential development electrical infrastructure assumed at $1.5k/lot based upon estimates and actuals.
2) Estimates are based upon per foot costs for a typical one mile construction
3) Rebuild 3ph 336ACSR: backyard @ $58/ft; along road @ $38/ft; new ground@ $18/ft
4) Rebuild 3ph 336ACSR double circuit: along road @ $89/ft; backyard @ $108/ft
5) Rebuild 3ph 750kcmil: in road @ $100/ft
6) Rebuild 1ph 1/0: subdivision @ $30/ft
7) Below Values are Engineering's best firm estimates, with scheduling subject to revisions depending upon operating priorities.
8) Crew Labor (PO and System) available for CIP work is 60% of total available due to PTO, Holidays, Outages, etc.
9) Engineering labor avaialble for CIP work is 60% of available due to PTO, Holidays, etc.
10) "YES" OH Materials charge for "YES" stock items such as transformers and meters.
11) Line Extension: Materials account for 80% of costs and labor accounts for 20% based upon average of C49424, C39437, C39439 actuals.
12) New Services (PO and Systems): Materials account for 45% of costs and labor accounts for 55% based upon 2013 & 2014 actuals.
13) OH Rebuilds: Materials 30%, Labor 35%, Equipment 10%, Overheads 25%
14) UG Rebuilds: Materials 35%, Labor 35%, Equipment 5%, Overheads 25%

CIP Project No. ES130009

SOUTHWEST SERVICE AREA INFRASTRUCTURE ACQUISTION

Per 2005 Electrical Service Area Agreement, purchase the depreciated value of Benton PUD infrastructure currently serving Hidden Hills Phase 1, BMID pumping station, and Reatta Ridge in 2015 and other PUD facilities in 2020 serving any new City annexed properties in this southwest service area.

COST TYPE	2024	2025	2025	2025	2026	2027	2028
MAT'L	$0	$0	$0	$0	$0	$0	$0
XPRT SRVS	$0	$0	$0	$0	$0	$0	$0
INSIDE LABOR	$0	$0	$0	$0	$0	$0	$0
EQUIP	$0	$0	$0	$0	$0	$0	$0
OH	$0	$0	$0	$0	$0	$0	$0
ENGR'NG	$0	$0	$0	$0	$1	$2	$3
TOTAL	**$0**	**$0**	**$0**	**$0**	**$1**	**$2**	**$3**

PROJECT TITLE	PROJECT DESCRIPTION
SOUTHWEST SERVICE AREA INFRASTRUCTURE ACQUISTION	Per 2005 Service Area Agreement, purchase the depreciated value of infrastructure for ~~Hidden Hills,~~ Reata Ridge ~~and BMID pump station in 2016~~ in 2018 and other facilities in 2021.
	Is inventory in stock? Yes / No NO

TYPE	2024	2024	2024	2024	2024	2024	2024
MAT'L	0	0	0	0	0	0	0
XPRT SRVS	0	0	0	0	0	0	0
INSIDE LABOR	0	0	0	0	0	0	0
EQUIP	0	0	0	0	0	0	0
OH	0	0	0	0	0	0	0
ENGR'NG	0	0	0	0	1	2	3
TOTAL	**0**	**0**	**0**	**0**	**0**	**0**	**0**

CIP Project No. ES130011

SYSTEM IMPROVEMENTS

Capital improvements to the electric utility infrastructure that are essential to community growth, regulatory compliance, and system reliability. These represent new improvements, some of which are required on an annual basis.

NOTE: All materials are charged to Div. 503.

COST TYPE	2024	2025	2025	2025	2026	2027	2028
MAT'L	$233,000	$203,000	$253,000	$253,000	$329,000	$203,000	$0
XPRT SRVS	$0	$0	$200,000	$0	$0	$0	$0
INSIDE LABOR	$155,000	$100,000	$120,000	$125,000	$172,000	$100,000	$0
EQUIP	$39,000	$39,000	$39,000	$39,000	$72,000	$39,000	$0
OH	$134,000	$104,000	$127,000	$130,000	$174,000	$104,000	$0
ENGR'NG	$32,000	$27,000	$45,000	$33,000	$45,000	$27,000	$0
TOTAL	**$593,000**	**$473,000**	**$784,000**	**$580,000**	**$792,000**	**$473,000**	**$0**

PROJECT TITLE	PROJECT DESCRIPTION	
RELAY REPLACEMENTS	REPLACE REF550 RELAYS WITH SEL 351S	
	Is inventory in stock? Yes / No	YES

TYPE	2024	2025	2026	2027	2028	2029	2030
MAT'L	0	0	0	0	0	0	0
XPRT SRVS	0	0	0	0	0	0	0
INSIDE LABOR	50,000	0	0	0	0	0	0
EQUIP	0	0	0	0	0	0	0
OH	27,000	0	0	0	0	0	0
ENGR'NG	5,000	0	0	0	0	0	0
TOTAL	**82,000**	**0**	**0**	**0**	**0**	**0**	**0**

POWER OPERATIONS	PROJECT DESCRIPTION								
NEW SERVICES (CABLE)	New services to customers. Numbers reflect appx. 450 services per year.	**TYPE**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
		MAT'L	203,000	203,000	203,000	203,000	203,000	203,000	0
		XPRT SRVS	0	0	0	0	0	0	0
		INSIDE LABOR	100,000	100,000	100,000	100,000	100,000	100,000	0
		EQUIP	39,000	39,000	39,000	39,000	39,000	39,000	0
		OH	104,000	104,000	104,000	104,000	104,000	104,000	0
		ENGR'NG	27,000	27,000	27,000	27,000	27,000	27,000	0
	Is inventory in stock? Yes / No YES	**TOTAL**	**473,000**	**473,000**	**473,000**	**473,000**	**473,000**	**473,000**	**0**

POWER FACTOR CORRECTION CAPACITORS	REDUCE SYSTEM LOSSES ON POWER TRANSFORMERS AND DISTRIBUTION SYSTEM BY INSTALLING POWER FACTOR CORRECTION CAPACITORS. THIS REDUCES REACTIVE ENERGY.	**TYPE**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
		MAT'L	0	0	0	50,000	0	0	0
		XPRT SRVS	0	0	0	0	0	0	0
		INSIDE LABOR	0	0	0	25,000	0	0	0
		EQUIP	0	0	0	0	0	0	0
		OH	0	0	0	26,000	0	0	0
		ENGR'NG	0	0	0	6,000	0	0	0
	Is inventory in stock? Yes / No YES	**TOTAL**	**0**	**0**	**0**	**107,000**	**0**	**0**	**0**

RES Radio Upgrade

Replace Operational Radios that are at end-of-life

Is inventory in stock? Yes / No NO

TYPE		2024	2025	2026	2027	2028	2029	2030
MAT'L	$	30,000.00	0	0	0	0	0	0
XPRT SRVS	$	-	0	0	0	0	0	0
INSIDE LABOR	$	5,000.00	0	0	0	0	0	0
EQUIP	$	-	0	0	0	0	0	0
OH	$	3,000.00	0	0	0	0	0	0
ENGR'NG	$	-	0	0	0	0	0	0
TOTAL	**$**	**38,000.00**	**0**	**0**	**0**	**0**	**0**	**0**

CIRCUIT SWITCHERS AT THAYER & STEVENS

NEW CIRCUIT SWITCHERS IN CONJUNCTION WITH BPA'S BUS REBUILD AT THAYER AND STEVENS, PART OF THE DOUBLE CIRCUIT 115Kv

THESE COSTS HAVE BEEN MOVED TO THE REBUILD PROJECTS

Is inventory in stock? Yes / No YES

TYPE	2024	2025	2026	2027	2028	2029	2030
MAT'L	0	0	0	0	0	0	0
XPRT SRVS	0	0	0	0	0	0	0
INSIDE LABOR	0	0	0	0	0	0	0
EQUIP	0	0	0	0	0	0	0
OH	0	0	0	0	0	0	0
ENGR'NG	0	0	0	0	0	0	0
TOTAL	**0**	**0**	**0**	**0**	**0**	**0**	**0**

GALA WAY 750 (Boring)

Extend a 750 circuit from Westcliffe Blvd to Sicily Ln along Gala Way. Set 2 new switch cabinets. Approximately 1500' of boring, and 800' of existing conduit.

Is inventory in stock? Yes / No YES

TYPE	2024	2025	2026	2027	2028	2029	2030
MAT'L	0	0	50,000	0	0	0	0
XPRT SRVS	0	0	200,000	0	0	0	0
INSIDE LABOR	0	0	20,000	0	0	0	0
EQUIP	0	0	0	0	0	0	0
OH	0	0	23,000	0	0	0	0
ENGR'NG	0	0	18,000	0	0	0	0
TOTAL	**0**	**0**	**311,000**	**0**	**0**	**0**	**0**

BMID SUBSTATION SECOND FEEDER

THIS PROJECT WILL EXTEND A SECOND FEEDER TO THE BADGER MOUNTAIN IRRIGATION DISTRICT SUBSTATION FROM SUNDANCE RIDGE.

Is inventory in stock? Yes / No YES

TYPE	2024	2025	2026	2027	2028	2029	2030
MAT'L	0	0	0	0	126,000	0	0
XPRT SRVS	0	0	0	0	0	0	0
INSIDE LABOR	0	0	0	0	72,000	0	0
EQUIP	0	0	0	0	33,000	0	0
OH	0	0	0	0	70000	0	0
ENGR'NG	0	0	0	0	18,000	0	0
TOTAL	**0**	**0**	**0**	**0**	**319,000**	**0**	**0**

CIP Project No. ES130010

RENEWAL & REPLACEMENT

Capital improvements to the electric utility infrastructure that are essential to community growth, regulatory compliance, and system reliability. These represent new improvements, some of which are required on an annual basis.
NOTE: Projects inside the substation are 504 and projects outside the substation are 503 budget.

COST TYPE	2024	2025	2026	2027	2028	2029	2030
MAT'L	$1,220,000	$1,320,000	$820,000	$880,000	$820,000	$820,000	$800,000
XPRT SRVS	$2,320,000	$2,700,000	$1,450,000	$1,510,000	$1,450,000	$1,450,000	$1,450,000
INSIDE LABOR	$40,000	$40,000	$40,000	$40,000	$40,000	$40,000	$40,000
EQUIP	$74,000	$74,000	$74,000	$74,000	$74,000	$74,000	$74,000
OH	$326,000	$351,000	$226,000	$226,000	$226,000	$226,000	$221,000
ENGR'NG	$237,000	$268,000	$155,000	$162,000	$155,000	$155,000	$155,000
TOTAL	**$4,217,000**	**$4,753,000**	**$2,765,000**	**$2,892,000**	**$2,765,000**	**$2,765,000**	**$2,740,000**

PROJECT TITLE | **PROJECT DESCRIPTION**

Install SEL-2440

Install 2440's to replace the PLC's at, Stevens Bank 3, First Street Bank 1 & 3, City View Bank 1, Richland Switch Bank 1, Thayer Bank 2.

NEED TO ADD COSTS FOR THIS PROJECT ONCE SCOPE HAS BEEN DEVELOPED

Is inventory in stock? Yes / No NO

TYPE	2024	2025	2026	2027	2028	2029	2030
MAT'L	0	0	0	0	0	0	0
XPRT SRVS	0	0	0	0	0	0	0
OUTSIDE LABOR	0	0	0	0	0	0	0
INSIDE LABOR	0	0	0	0	0	0	0
EQUIP	0	0	0	0	0	0	0
OH	0	0	0	0	0	0	0
ENGR'NG	0	0	0	0	0	0	0
TOTAL	**0**	**0**	**0**	**0**	**0**	**0**	**0**

METER REPLACEMENT & UPGRADE

Combined dollars from System Improvements to here These replace existing meters as opposed to New Meters which are addressed under "System Improvements". Replace appx.200 meters per year.
(This may be zeroed out once SmartGrid meters are installed.

Is inventory in stock? Yes / No YES

TYPE	2024	2025	2026	2027	2028	2029	2030
MAT'L	20,000	20,000	20,000	20,000	20,000	20,000	0
XPRT SRVS	0	0	0	0	0	0	0
INSIDE LABOR	0	0	0	0	0	0	0
EQUIP	0	0	0	0	0	0	0
OH	5,000	5,000	5,000	5,000	5,000	5,000	0
ENGR'NG	0	0	0	0	0	0	0
TOTAL	**25,000**	**25,000**	**25,000**	**25,000**	**25,000**	**25,000**	**0**

SUBSTATION POWER TRANSFORMER OIL FILTRATION SYSTEMS

DESIGN AND CONTRACT OUT THE INSTALLATION OF AN ON-LINE FILTRATION SYSTEM FOR THE SUBSTATION POWER TRANSFORMER LOAD TAP CHANGER.

Is inventory in stock? Yes / No NO

TYPE	2024	2025	2026	2027	2028	2029	2030
MAT'L	0	0	0	60,000	0	0	0
XPRT SRVS	0	0	0	60,000	0	0	0
INSIDE LABOR	0	0	0	0	0	0	0
EQUIP	0	0	0	0	0	0	0
OH	0	0	0	0	0	0	0
ENGR'NG	0	0	0	7,000	0	0	0
TOTAL	**0**	**0**	**0**	**127,000**	**0**	**0**	**0**

POWER OPERATIONS	PROJECT DESCRIPTION									
POLE REPLACEMENT PROGRAM	POLE TESTING IDENTIFIES DETERIORATED POLES THAT SHOULD BE REPLACED OR REINFORCED WITH STEEL POLE STUBS. TESTING AND TREATING POLES EXTENDS THE LIFE OF EXISTING POLES AND HELPS TO IDENTIFY POLES THAT NEED STUBBING OR REPLACING.		**TYPE**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
			MAT'L	300,000	300,000	300,000	300,000	300,000	300,000	300,000
			XPRT SRVS	200,000	200,000	200,000	200,000	200,000	200,000	200,000
			INSIDE LABOR	0	0	0	0	0	0	0
	Revised on 01/17-Less 350K from "Outside labor"		EQUIP	4,000	4,000	4,000	4,000	4,000	4,000	4,000
			OH	75,000	75,000	75,000	75,000	75,000	75,000	75,000
			ENGR'NG	35,000	35,000	35,000	35,000	35,000	35,000	35,000
	Is inventory in stock? Yes / No	YES	**TOTAL**	**614,000**	**614,000**	**614,000**	**614,000**	**614,000**	**614,000**	**614,000**

Bypass Relocation	Completes Strong Tie in LRP (need to get number for LRP) Underground Feeder 81 out of Richland Switch behind sound wall.		**TYPE**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
			MAT'L	400,000	0	0	0	0	0	0
			XPRT SRVS	1,000,000	0	0	0	0	0	0
			INSIDE LABOR	0	0	0	0	0	0	0
			EQUIP	0	0	0	0	0	0	0
			OH	100,000	0	0	0	0	0	0
			ENGR'NG	90,000	0	0	0	0	0	0
	Is inventory in stock? Yes / No	YES	**TOTAL**	**1,590,000**	**0**	**0**	**0**	**0**	**0**	**0**

UPGRADE SCADA SYSTEM	UPGRADE / NEW SCADA SYSTEM		**TYPE**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
			MAT'L	0	0	0	0	0	0	0
			XPRT SRVS	120,000	0	0	0	0	0	0
			INSIDE LABOR	0	0	0	0	0	0	0
			EQUIP	0	0	0	0	0	0	0
			OH	0	0	0	0	0	0	0
			ENGR'NG	7,000	0	0	0	0	0	0
	Is inventory in stock? Yes / No	YES	**TOTAL**	**127,000**	**0**	**0**	**0**	**0**	**0**	**0**
	Is inventory in stock? Yes / No	YES								

UNDERGROUND CABLE REPLACEMENT	Replace aging underground cables - Individual projects will be identifed *Including boring and drilling projects.		**TYPE**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
			MAT'L	$ 500,000	$ 1,000,000	$ 500,000	$ 500,000	$ 500,000	$ 500,000	$ 500,000
			XPRT SRVS	$ 1,000,000	$ 2,500,000	$ 1,250,000	$ 1,250,000	$ 1,250,000	$ 1,250,000	$ 1,250,000
	2025 - Hills Mobile Home		OUTSIDE LABOR	$ -	$ -	$ -	$ -	$ -	$ -	$ -
			INSIDE LABOR	$ 40,000	$ 40,000	$ 40,000	$ 40,000	$ 40,000	$ 40,000	$ 40,000
			EQUIP	$ 70,000	$ 70,000	$ 70,000	$ 70,000	$ 70,000	$ 70,000	$ 70,000
			OH	$ 146,000	$ 271,000	$ 146,000	$ 146,000	$ 146,000	$ 146,000	$ 146,000
			ENGR'NG	$ 105,000	$ 233,000	$ 120,000	$ 120,000	$ 120,000	$ 120,000	$ 120,000
	Is inventory in stock? Yes / No	YES	**TOTAL**	**$ 1,861,000**	**$ 4,114,000**	**$ 2,126,000**	**$ 2,126,000**	**$ 2,126,000**	**$ 2,126,000**	**$ 2,126,000**

CIP Project No. ES130005

ADVANCED METERING INFRASTRUCTURE UTILITIES PROJECT

Complete a detailed design and implement an electrical utility smart grid program to cost-effectively improve utility operations and provide the utility customers with options to control their power consumption and usage patterns.

COST TYPE	2024	2025	2026	2027	2028	2029	2030
MAT'L	$0	$0	$0	$0	$0	$0	$0
XPRT SRVS	$0	$0	$0	$0	$0	$0	$0
INSIDE LABOR	$0	$0	$0	$0	$0	$0	$0
EQUIP	$0	$0	$0	$0	$0	$0	$0
OH	$0	$0	$0	$0	$0	$0	$0
ENGR'NG	$0	$0	$0	$0	$0	$0	$0
TOTAL	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
	0	0	0	0	0	0	0

PROJECT TITLE	PROJECT DESCRIPTION
ADVANCED METERING INFRASTRUCTURE & SMART GRID	Smart Grid System (AMI/MDMS/OMS/Prepay) - UtiliWorks Estimate 6/2014 of $5.2M material, $1.2M expert services. Labor for inst comm meters: 2500@$45/hr*4hr
	Is inventory in stock? Yes / No NO

TYPE	2024	2025	2026	2027	2028	2029	2030
MAT'L	0	0	0	0	0	0	0
XPRT SRVS	0	0	0	0	0	0	0
INSIDE LABOR	0	0	0	0	0	0	0
EQUIP	0	0	0	0	0	0	0
OH	0	0	0	0	0	0	0
ENGR'NG	0	0	0	0	0	0	0
TOTAL	**0**	**0**	**0**	**0**	**0**	**0**	**0**

CIP Project No. ES130007

SUBSTATION IMPROVEMENTS

A variety of major improvement projects within the eight existing electric utility substation sites. Examples of work includes new transformer banks at Snyder and 115 kV bus modification at Tapteal substation.

COST TYPE	2024	2025	2026	2027	2028	2029	2030
MAT'L	$3,100,000	$3,000,000	$3,250,000	$3,250,000	$0	$3,250,000	$3,000,000
XPRT SRVS	$1,510,000	$1,550,000	$2,090,000	$1,384,000	$659,000	$2,259,000	$1,384,000
INSIDE LABOR	$0	$0	$0	$0	$0	$0	$0
EQUIP	$0	$0	$0	$0	$0	$0	$0
OH	$0	$0	$813,000	$813,000	$0	$0	$0
ENGR'NG	$277,000	$274,000	$369,000	$327,000	$40,000	$331,000	$23,000
TOTAL	**$4,887,000**	**$4,824,000**	**$6,522,000**	**$5,774,000**	**$699,000**	**$5,840,000**	**$4,407,000**

City View Bank #2

Add a new bank at City View Sub to support load growth north of City Shops area and Badger Mountain South
2022-Design, Transformer (TB Delivered early 2023)
2023-Remainder of Transformer cost, MCS, construction

Is inventory in stock? Yes / No NO

TYPE	2024	2025	2026	2027	2028	2029	2030
MAT'L	0	0	0	0	0	0	0
XPRT SRVS	0	0	0	0	0	0	0
INSIDE LABOR	0	0	0	0	0	0	0
EQUIP	0	0	0	0	0	0	0
OH	0	0	0	0	0	0	0
ENGR'NG	0	0	0	0	0	0	0
TOTAL	0	0	0	0	0	0	0

STEVENS SUBSTATION - BANK 1 REBUILD

Replace aging transformer and switchgear in coordination with BPA's Transmission Line and Bus Rebuild Project.

Assumed Costs: 2023

Transformer: $1.6M

Metalclad: $1.1M

SC & Bus Switches: $300K

Design: $275K, Construction: $1.5M

Is inventory in stock? Yes / No NO

TYPE	2024	2025	2026	2027	2028	2029	2030
MAT'L	3,000,000	0	0	0	0	0	0
XPRT SRVS	1,500,000	0	0	0	0	0	0
INSIDE LABOR	0	0	0	0	0	0	0
EQUIP	0	0	0	0	0	0	0
OH	0	0	0	0	0	0	0
ENGR'NG	270,000	0	0	0	0	0	0
TOTAL	**4,770,000**	**0**	**0**	**0**	**0**	**0**	**0**

Thayer Bank #1, Replace Transformer and MC

Replace aging transformer and switchgear. Planned for design in 2023, build 2025

Assumed Costs: 2023

Transformer: $1.6M

Metalclad: $1.1M

SC & Bus Switches: $300K

Design: $275K, Construction $1M

Is inventory in stock? Yes / No NO

TYPE	2024	2025	2026	2027	2028	2029	2030
MAT'L	0	3000000	0	0	0	0	0
XPRT SRVS	0	1000000	0	0	0	0	0
INSIDE LABOR	0	0	0	0	0	0	0
EQUIP	0	0	0	0	0	0	0
OH	0	0	0	0	0	0	0
ENGR'NG	0	240,000	0	0	0	0	0
TOTAL	0	4,240,000	0	0	0	0	0

Sandhill Crane Bank 3

Expand existing substation to add two new banks. Bank 3 will be designed in 2024, and construction 2025

Assumed Costs: 2023

Transformer: $1.6M

Metalclad: $1.1M, Control House: $250K

SC & Bus Switches: $300K

Design: $275K, Construction $1M

TYPE	2024	2025	2026	2027	2028	2029	2030
MAT'L	0	0	3,250,000	0	0	0	0
XPRT SRVS	0	275,000	1,500,000	0	0	0	0
INSIDE LABOR	0	0	0	0	0	0	0
EQUIP	0	0	0	0	0	0	0
OH	0	0	813,000	0	0	0	0
ENGR'NG	0	17,000	334,000	0	0	0	0

			TYPE	2024	2025	2026	2027	2028	2029	2030
	Is inventory in stock? Yes / No	YES	TOTAL	0	292,000	5,897,000	0	0	0	0

Sandhill Crane Bank 4

Expand existing substation to add two new banks. Bank 4 will be designed in 2024, and construction 2026

Assumed Costs: 2023

Transformer: $1.6M

Metalclad: $1.1M, Control House: $250K

SC & Bus Switches: $300K

Design: $275K, Construction $1M

Is inventory in stock? Yes / No — YES

TYPE	2024	2025	2026	2027	2028	2029	2030
MAT'L	0	0	0	3,250,000	0	0	0
XPRT SRVS	0	275,000	0	1,000,000	0	0	0
INSIDE LABOR	0	0	0	0	0	0	0
EQUIP	0	0	0	0	0	0	0
OH	0	0	0	813,000	0	0	0
ENGR'NG	0	17,000	0	304,000	0	0	0
TOTAL	0	292,000	0	5,367,000	0	0	0

THAYER BANK 3 - REPLACE TRANSFORMER AND METAL CLAD

Replace aging transformer and switchgear. Planned for design in 2028, build 2029

Assumed Costs: 2023

Transformer: $1.6M

Metalclad: $1.1M

SC & Bus Switches: $300K

Design: $275K, Construction $1M

Is inventory in stock? Yes / No — NO

TYPE	2024	2025	2026	2027	2028	2029	2030
MAT'L	0	0	0	0	0	3000000	0
XPRT SRVS	0	0	0	0	275000	1000000	0
INSIDE LABOR	0	0	0	0	0	0	0
EQUIP	0	0	0	0	0	0	0
OH	0	0	0	0	0	0	0
ENGR'NG	0	0	0	0	17,000	240,000	0
TOTAL	0	0	0	0	292,000	4,240,000	0

STEVENS SUBSTATION - BANK 2 REBUILD

Replace aging transformer and switchgear. Planned for design in 2029, build 2030

Assumed Costs: 2023

Transformer: $1.6M

Metalclad: $1.1M

SC & Bus Switches: $300K

Design: $275K

Is inventory in stock? Yes / No — NO

TYPE	2024	2025	2026	2027	2028	2029	2030
MAT'L	0	0	0	0	0	0	3000000
XPRT SRVS	0	0	0	0	0	275000	1000000
INSIDE LABOR	0	0	0	0	0	0	0
EQUIP	0	0	0	0	0	0	0
OH	0	0	0	0	0	0	0
ENGR'NG	0	0	0	0	0	17,000	0
TOTAL	0	0	0	0	0	292,000	4,000,000

GPS CLOCKS

Purchase and install GPS clocks in substations to schronize all protective relays and enable staff to determine the sequence of events during outages.

Is inventory in stock? Yes / No — NO

TYPE	2024	2025	2026	2027	2028	2029	2030
MAT'L	0	0	0	0	0	0	0
XPRT SRVS	0	0	0	0	0	0	0
INSIDE LABOR	0	0	0	0	0	0	0
EQUIP	0	0	0	0	0	0	0
OH	0	0	0	0	0	0	0
ENGR'NG	0	0	0	0	0	0	0
TOTAL	0	0	0	0	0	0	0

SUBSTATION SECURITY - AREA LIGHTING AND VIDEO

Install security lighting and video system in substations for physical protection and to reduce the theft of copper and aluminum materials integral to the operation of the electrical utility.

Is inventory in stock? Yes / No — NO

TYPE	2024	2025	2026	2027	2028	2029	2030
MAT'L	100,000	0	0	0	0	0	0
XPRT SRVS	10,000	0	590,000	0	0	0	0
INSIDE LABOR	0	0	0	0	0	0	0
EQUIP	0	0	0	0	0	0	0
OH	0	0	0	0	0	0	0
ENGR'NG	7,000	0	35,000	0	0	0	0
TOTAL	117,000	0	625,000	0	0	0	0

Spill Containment (SPCC)

SPCC First St Sub (2027), BMID (2028), Thayer (2029), Stevens (2030)

Is inventory in stock? Yes / No — YES

TYPE	2024	2025	2026	2027	2028	2029	2030
MAT'L	0	0	0	0	0	0	0
XPRT SRVS	0	0	0	384,000	384,000	384,000	384,000
INSIDE LABOR	0	0	0	0	0	0	0
EQUIP	0	0	0	0	0	0	0
OH	0	0	0	0	0	0	0
ENGR'NG	0	0	0	23,000	23,000	23,000	23,000
TOTAL	**0**	**0**	**0**	**407,000**	**407,000**	**407,000**	**407,000**

TAPTEAL SUBSTATION - 115KV BUS UPGRADE

TAPTEAL'S 115KV BUS CONFIGUARTION IS PROBLEMATIC AND REQUIRES AN ENTIRE SUBSTATION OUTAGE TO PERFORM SOME WORK IN THE SUBSTATION.

Design in 27

Build in 28

Need better est

COMMENTS: Is inventory in stock? Yes / No — NO

TYPE	2024	2025	2026	2027	2028	2029	2030
MAT'L	0	0	0	0	0	250,000	0
XPRT SRVS	0	0	0	0	0	600,000	0
INSIDE LABOR	0	0	0	0	0	0	0
EQUIP	0	0	0	0	0	0	0
OH	0	0	0	0	0	0	0
ENGR'NG	0	0	0	0	0	51,000	0
TOTAL	**0**	**0**	**0**	**0**	**0**	**901,000**	**0**

CIP Project No. ES130001

DALLAS RD AREA IMPROVEMENTS (FORMERLY DALLAS RD SUB

Plan, design, and construct a new electrical system substation and connect via new and existing transmission power lines into the electric system grid.

COST TYPE	2024	2025	2026	2027	2028	2029	2030
MAT'L	$0	$0	$0	$3,416,000	$0	$0	$0
XPRT SRVS	$0	$0	$550,000	$3,000,000	$0	$0	$0
INSIDE LABOR	$0	$0	$0	$166,000	$0	$0	$0
EQUIP	$0	$0	$0	$41,000	$0	$0	$0
OH	$0	$0	$0	$130,000	$0	$0	$0
ENGR'NG	$0	$0	$33,000	$406,000	$0	$0	$0
TOTAL	**$0**	**$0**	**$583,000**	**$7,159,000**	**$0**	**$0**	**$0**

DALLAS ROAD SUBSTATION

Replace aging transformer and switchgear. Planned for design in 2026, build 2027, Possible shared location with BPUD

Assumed Costs: 2023

Transformer: $1.6M

Metalclad: $1.1M, Control House: $250K

SC & Bus Switches: $300K

Design: $550K, Construction: $3M

Is inventory in stock? Yes / No — NO

TYPE	2024	2025	2026	2027	2028	2029	2030
MAT'L	0	0	0	3,250,000	0	0	0
XPRT SRVS	0	0	550,000	3,000,000	0	0	0
INSIDE LABOR	0	0	0	0	0	0	0
EQUIP	0	0	0	0	0	0	0
OH	0	0	0	0	0	0	0
ENGR'NG	0	0	33,000	375,000	0	0	0
TOTAL	**0**	**0**	**583,000**	**6,625,000**	**0**	**0**	**0**

DALLAS RD SUBSTATION FEEDER 1

EXTEND FEEDER FROM DALLAS ROAD SUBSTATION TO DALLAS RD 1,500 FEET EAST.

TYPE	2024	2025	2026	2027	2028	2029	2030
MAT'L	0	0	0	40,000	0	0	0
XPRT SRVS	0	0	0	0	0	0	0
INSIDE LABOR	0	0	0	40,000	0	0	0
EQUIP	0	0	0	11,000	0	0	0

			TYPE	2024	2025	2026	2027	2028	2029	2030
			OH	0	0	0	31,000	0	0	0
			ENGR'NG	0	0	0	7,000	0	0	0
	Is inventory in stock? Yes / No	YES	TOTAL	0	0	0	129,000	**0**	**0**	**0**

			TYPE	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
DALLAS RD SUBSTATION FEEDER 2	EXTEND FEEDER FROM DALLAS ROAD SUBSTATION TO DALLAS RD 1,500 FEET EAST.		MAT'L	0	0	0	42,000	0	0	0
			XPRT SRVS	0	0	0	0	0	0	0
			INSIDE LABOR	0	0	0	42,000	0	0	0
			EQUIP	0	0	0	10,000	0	0	0
			OH	0	0	0	33,000	0	0	0
			ENGR'NG	0	0	0	8,000	0	0	0
	Is inventory in stock? Yes / No	YES	TOTAL	0	0	0	135,000	**0**	**0**	**0**

			TYPE	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
DALLAS RD SUBSTATION FEEDER 3	EXTEND FEEDER FROM DALLAS ROAD SUBSTATION TO DALLAS RD 1,500 FEET EAST.		MAT'L	0	0	0	42,000	0	0	0
			XPRT SRVS	0	0	0	0	0	0	0
			INSIDE LABOR	0	0	0	42,000	0	0	0
			EQUIP	0	0	0	10,000	0	0	0
			OH	0	0	0	33,000	0	0	0
			ENGR'NG	0	0	0	8,000	0	0	0
	Is inventory in stock? Yes / No	YES	TOTAL	0	0	0	135,000	**0**	**0**	**0**

			TYPE	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
DALLAS RD SUBSTATION FEEDER 4	Extend feeder from Dallas Rd Substation to Dalls Rd 1,500 feet east.		MAT'L	0	0	0	42,000	0	0	0
			XPRT SRVS	0	0	0	0	0	0	0
			INSIDE LABOR	0	0	0	42,000	0	0	0
			EQUIP	0	0	0	10,000	0	0	0
			OH	0	0	0	33,000	0	0	0
			ENGR'NG	0	0	0	8,000	0	0	0
	Is inventory in stock? Yes / No	YES	TOTAL	0	0	0	135,000	**0**	**0**	**0**

			TYPE	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
DALLAS RD FEEDER REINFORCEMENT	EXTEND SECOND FEEDER FROM THE ENTRANCE TO WHITE BLUFFS SUBDIVISION TO OVERHEAD POLE LINE 5,000 FEET SOUTH.		MAT'L	0	0	0	0	0	0	0
			XPRT SRVS	0	0	0	0	0	0	0
			INSIDE LABOR	0	0	0	0	0	0	0
			EQUIP	0	0	0	0	0	0	0
			OH	0	0	0	0	0	0	0
			ENGR'NG	0	0	0	0	0	0	0
	Is inventory in stock? Yes / No	NO	TOTAL	0	0	0	0	**0**	**0**	**0**

CIP Project No. ES130004

LESLIE RD SUBSTATION

Plan, design, and construct a new electrical system substation and connect into the electrical system grid operated by Bonneville Power Administration (BPA). Additionally, plan, design and construct primary underground distribution feeders from new substation to the City's new and existing electrical system.

COST TYPE	2024	2025	2026	2027	2028	2029	2030
MAT'L	$0	$0	$0	$0	$0	$0	$0
XPRT SRVS	$0	$0	$0	$0	$0	$0	$0
INSIDE LABOR	$0	$0	$0	$0	$0	$0	$0
EQUIP	$0	$0	$0	$0	$0	$0	$0
OH	$0	$0	$0	$0	$0	$0	$0
ENGR'NG	$0	$0	$0	$0	$0	$0	$0
TOTAL	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**

CIP Project No. ES130002

FUSION SUBSTATION

New Substation to serve new industrial load in the DOE Transfer land north of Horn Rapids Rd.

COST TYPE	2024	2025	2026	2027	2028	2029	2030
MAT'L	$0	$0	$0	$0	$3,250,000	$0	$0
XPRT SRVS	$0	$0	$0	$550,000	$3,000,000	$0	$0
INSIDE LABOR	$0	$0	$0	$0	$0	$0	$0
EQUIP	$0	$0	$0	$0	$0	$0	$0
OH	$0	$0	$0	$0	$0	$0	$0
ENGR'NG	$0	$0	$0	$33,000	$375,000	$0	$0
TOTAL	**$0**	**$0**	**$0**	**$583,000**	**$6,625,000**	**$0**	**$0**

Fusion Substation

NEW SUBSTATION AND TRANSMISSION LINES TO SERVE DOE LAND TRANSFER AREA. Design in 2027, Construction in 2028 (Could be sooner if area develops)

2023 - $500k for Transmission Design

Need to add a Transmission line project line

Is inventory in stock? Yes / No NO

TYPE	2024	2025	2026	2027	2028	2029	2030
MAT'L	0	0	0	0	3,250,000	0	0
XPRT SRVS	0	0	0	550,000	3,000,000	0	0
INSIDE LABOR	0	0	0	0	0	0	0
EQUIP	0	0	0	0	0	0	0
OH	0	0	0	0	0	0	0
ENGR'NG	0	0	0	33,000	375,000	0	0
TOTAL	**0**	**0**	**0**	**583,000**	**6,625,000**	**0**	**0**

CIP Project No. ES130003

GATEWAY SUBSTATION: HORN RAPIDS INDUSTRIAL AREA - DESIGN AND CONSTRUCTION

New substation for the Horn Rapids Industrial Park. One 28,000 KVA capacity transformer and major materials purchased by City. Substation to be constructed and commissioned by the end of 2021.

COST TYPE	2024	2025	2026	2027	2028	2029	2030
MAT'L	$0	$0	$460,800	$345,600	$172,800	$0	$0
XPRT SRVS	$0	$0	$0	$0	$0	$0	$0
INSIDE LABOR	$0	$0	$115,200	$86,400	$43,200	$0	$0
EQUIP	$0	$0	$0	$0	$0	$0	$0
OH	$0	$0	$61,000	$46,000	$23,000	$0	$0
ENGR'NG	$0	$0	$38,000	$28,000	$14,000	$0	$0
TOTAL	**$0**	**$0**	**$675,000**	**$506,000**	**$253,000**	**$0**	**$0**

GATEWAY Substation

New substation and transmission lines to serve Horn Rapids Industrial Area as identified from HDR Long Range Plan.

TYPE	2024	2025	2026	2027	2028	2029	2030
MAT'L	0	0	0	0	0	0	
XPRT SRVS	0	0	0	0	0	0	0
INSIDE LABOR	0	0	0	0	0	0	0
EQUIP	0	0	0	0	0	0	0

			OH	0	0	0	0	0	0	0
			ENGR'NG	0	0	0	0	0	0	0
	Is inventory in stock? Yes / No	NO	TOTAL	0	0	0	0	0	0	0

Gateway Feeder 1	Feeder 1 - planning stage 5000' $72/ft		TYPE	2024	2025	2026	2027	2028	2029	2030
			MAT'L	0	0	0	0	0	0	0
			XPRT SRVS	0	0	0	0	0	0	0
			INSIDE LABOR	0	0	0	0	0	0	0
			EQUIP	0	0	0	0	0	0	0
			OH	0	0	0	0	0	0	0
			ENGR'NG	0	0	0	0	0	0	0
	Is inventory in stock? Yes / No	NO	TOTAL	0	0	0	0	0	0	0

Gateway Feeder 2	Feeder 2 - planning stage 5000'		TYPE	2024	2025	2026	2027	2028	2029	2030
			MAT'L	0	0	0	0	0	0	0
			XPRT SRVS	0	0	0	0	0	0	0
			INSIDE LABOR	0	0	0	0	0	0	0
			EQUIP	0	0	0	0	0	0	0
			OH	0	0	0	0	0	0	0
			ENGR'NG	0	0	0	0	0	0	0
	Is inventory in stock? Yes / No	NO	TOTAL	0	0	0	0	0	0	0

Gateway Feeder 3	Feeder 3 - planning stage 5000'		TYPE	2024	2025	2026	2027	2028	2029	2030
			MAT'L	0	0	288,000	0	0	0	0
			XPRT SRVS	0	0	0	0	0	0	0
			INSIDE LABOR	0	0	72,000	0	0	0	0
			EQUIP	0	0	0	0	0	0	0
			OH	0	0	38,000	0	0	0	0
			ENGR'NG	0	0	24,000	0	0	0	0
	Is inventory in stock? Yes / No	NO	TOTAL	0	0	422,000	0	0	0	0

Gateway Feeder 4	Feeder 4 - planning stage 6000'		TYPE	2024	2025	2026	2027	2028	2029	2030
			MAT'L	0	0	172,800	172,800	0	0	0
			XPRT SRVS	0	0	0	0	0	0	0
			INSIDE LABOR	0	0	43,200	43,200	0	0	0
			EQUIP	0	0	0	0	0	0	0
			OH	0	0	23,000	23,000	0	0	0
			ENGR'NG	0	0	14,000	14,000	0	0	0
	Is inventory in stock? Yes / No	NO	TOTAL	0	0	253,000	253,000	0	0	0

Gateway Feeder 5	Feeder 5 - planning stage 6000'		TYPE	2024	2025	2026	2027	2028	2029	2030
			MAT'L	0	0	0	172,800	172,800	0	0
			XPRT SRVS	0	0	0	0	0	0	0
			INSIDE LABOR	0	0	0	43,200	43,200	0	0
			EQUIP	0	0	0	0	0	0	0
			OH	0	0	0	23,000	23,000	0	0
			ENGR'NG	0	0	0	14,000	14,000	0	0
	Is inventory in stock? Yes / No	NO	TOTAL	0	0	0	253,000	253,000	0	0

CIP Project No. ES130008

LINE EXTENSIONS - NEW DEVELOPMENTS

Capital improvement projects primarily for the purpose of extending electric utility infrastructure to new electric load.

COST TYPE	2024	2025	2026	2027	2028	2029	2030
MAT'L	$200,000	$50,000	$0	$0	$0	$0	$0
XPRT SRVS	$0	$0	$0	$0	$0	$0	$0
INSIDE LABOR	$400,000	$400,000	$400,000	$400,000	$400,000	$400,000	$400,000
EQUIP	$65,000	$65,000	$65,000	$65,000	$65,000	$65,000	$65,000
OH	$262,000	$225,000	$212,000	$212,000	$212,000	$212,000	$212,000
ENGR'NG	$56,000	$44,000	$41,000	$41,000	$41,000	$41,000	$41,000
TOTAL	**$983,000**	**$784,000**	**$718,000**	**$718,000**	**$718,000**	**$718,000**	**$718,000**

PROJECT TITLE	PROJECT DESCRIPTION
LINE EXTENSION PROJECTS	LINE EXTENSIONS PROJECT FUNDING WHERE NEW ELECTRICAL INFRASTRUCTURE IS INSTALLED BETWEEN THE CUSTOMER AND THE CITY ELECTRICAL DISTRIBUTION SYSTEM.

Is inventory in stock? Yes / No yes

TYPE	2024	2025	2026	2027	2028	2029	2030
MAT'L	200,000	50,000	0	0	0	0	0
XPRT SRVS	0	0	0	0	0	0	0
INSIDE LABOR	400,000	400,000	400,000	400,000	400,000	400,000	400,000
EQUIP	65,000	65,000	65,000	65,000	65,000	65,000	65,000
OH	262,000	225,000	212,000	212,000	212,000	212,000	212,000
ENGR'NG	56,000	44,000	41,000	41,000	41,000	41,000	41,000
TOTAL	**983,000**	**784,000**	**718,000**	**718,000**	**718,000**	**718,000**	**718,000**

UTILITY ADVISORY COMMITTEE AGENDA ITEM COVERSHEET

Meeting Date: 7/11/2023 Agenda Category: Other Informational Items

Prepared By: Clint Whitney, Energy Services Director

Subject:
Resource Adequacy - 3rd Annual Webinar by WA Utilities and Transportation Commission and WA Department of Commerce

Department:
Energy Services

Recommended Motion:
No action needed.

Summary:
The Washington State Utilities and Transportation Commission (UTC) and Washington Department of Commerce (DOC) will conduct their third annual meeting on energy resource adequacy. Previous presentations as well as additional information on the latest webinar is available at the CETA Resource Adequacy website:
https://www.commerce.wa.gov/growing-the-economy/energy/ceta/resource-adequacy/

Presentations and discussions should discuss current, short term and long term regional adequacy issues, including:

- Recent assessments of electricity demand and supply
- The industry's progress in developing a coordinated resource adequacy program
- Other actions utilities are taking to ensure resource adequacy

Key timeframes ahead:

- 2025 when the last electrical generation from coal ceases to be allowed, with 730 MW from Centralia #2 going offline, which ends approximately 4GW of coal generation in the greater NW area.
- 2025-2028 gap in resource adequacy.
- 2028 when binding resource adequacy commitments are required from the Balancing Authority Areas (BAA) participating in the Western Resource Area Program (WRAP). Note: BPA is a WRAP participant.

The meeting is open to the public and will be:
Monday, July 24, 2023, 9AM-3PM
Zoom meeting link
Zoom meeting ID: 844 6081 9521
Passcode: 436592
Dial-in, if needed: (253)215-8782

Fiscal Impact:
There is no fiscal impact.

Attachments:

UTILITY ADVISORY COMMITTEE AGENDA ITEM COVERSHEET

Meeting Date: 7/11/2023   Agenda Category: Other Informational Items

Prepared By: Clint Whitney, Energy Services Director

Subject:
Advanced Metering Infrastructure (AMI) Status

Department:
Energy Services

Recommended Motion:
No action needed.

Summary:
The Advanced Metering Infrastructure (AMI) project continues to make progress with the installation of electric and water meters. An outage management map and a customer portal for access to load profile data still remains to be implemented by the end of the year. As of July 6, 2023: 27,532 electric meters and 15,413 water meters have been installed. This represents approximately 95% of electric meters and 65% of water meters that have been completed. Attached is a graph of the electric and water installation status.

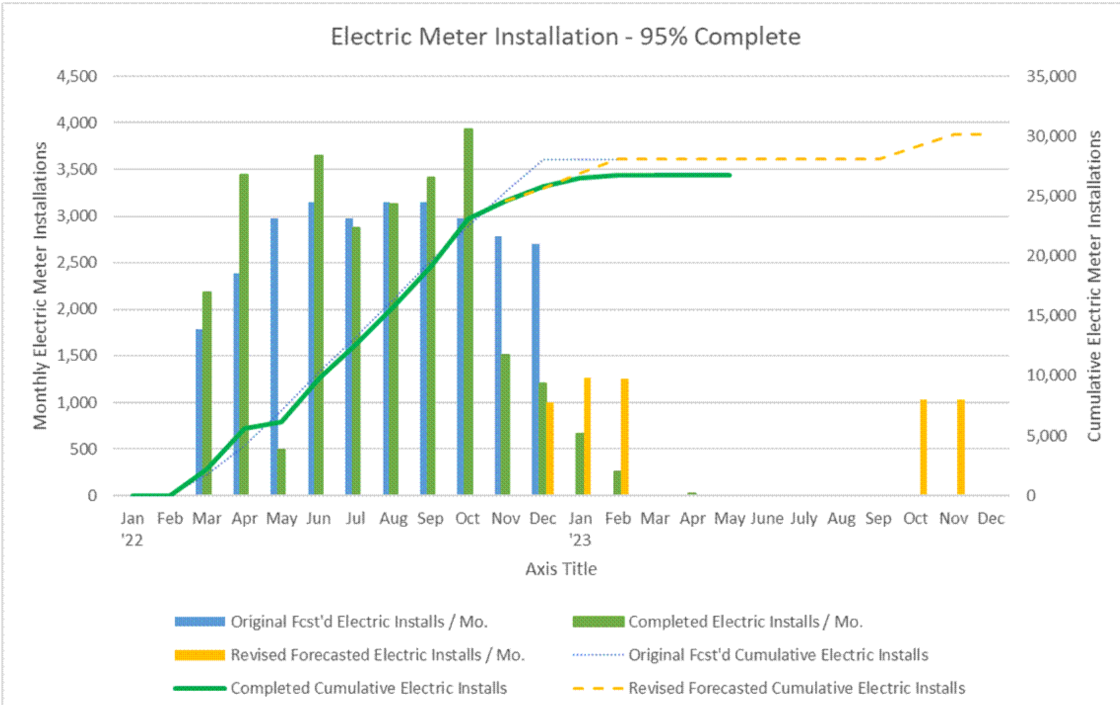
Fiscal Impact:
The AMI project was budgeted in 2023 and for previous years. There is no additional fiscal impact.

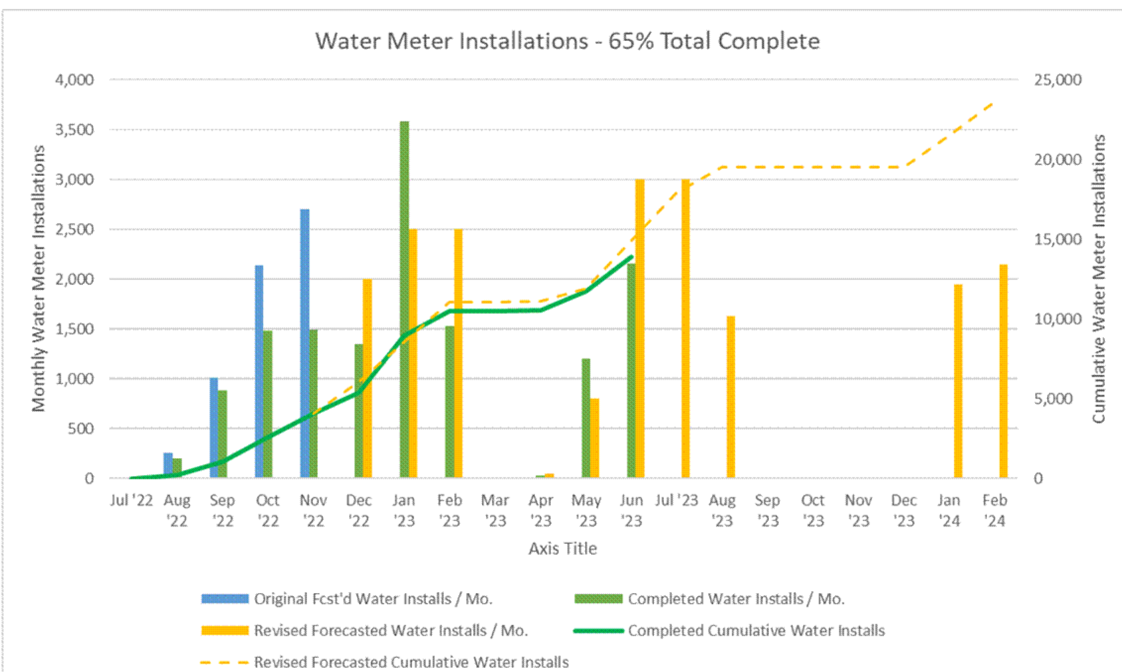
Attachments:
1. AMI Installation Status - 07062023

AMI Installation Status:

- AMI installation status (Active + Installed+ Disconnected) as of July 6th: 27,532 electric & 15,413 water meters installed.

- Electric and Water Meter Installations as of 6/21:





Audits as of 6/21

	Elec WO Completed	Elec Audits Completed	Elec Audit %	Water WO Completed	Water Audits Completed	Water Audit %	Total WO Completed	Total Audits Completed	Total Audit %
2022 Totals	25,809	1,362	5%	5,400	7	0%	31,209	1,369	4%
Jan '23	663	153	23%	3,581	313	9%	4,244	466	11%
Feb '23	256	3	1%	1,529	667	44%	1,785	670	38%
Mar '23	-	-	-	-	770	-	-	770	-
Apr '23	26	-	0%	26	563	2165%	52	563	1083%
May '23	-	-	-	1,199	-	0%	1,199	-	0%
Jun '23	-	-	-	2,159	208	10%	2,159	208	10%
Grand Total	26,754	1,518	6%	13,894	2,528	18%	40,648	4,046	10%

UTILITY ADVISORY COMMITTEE AGENDA ITEM COVERSHEET

Richland Washington

Meeting Date: 7/11/2023 Agenda Category: Other Informational Items

Prepared By: Clint Whitney, Energy Services Director

Subject:
Forward Agenda Items

Department:
Energy Services

Recommended Motion:
No action needed.

Summary:

September
- Resource Adequacy and Regional Transmission Organization (RTO) (RES)

November
- Electric Services Rate Recommendation

January
- Election of UAC Chair and Vice Chair
- Electric Cost of Service Analysis (COSA)
- Review Net Metering Study Results (RES)

Fiscal Impact:
There is no fiscal impact.

Attachments: