ROCHESTER PUBLIC UTILITIES
WE PLEDGE, WE DELIVER

MEETING AGENDA – JUNE 29, 2021

COMMUNITY ROOM
4000 EAST RIVER ROAD NE
ROCHESTER, MN 55906

4:00 PM

The Rochester Public Utility Board is holding this meeting by telephone or other electronic means pursuant to Minnesota Statutes Section 13D.021. Some Board members may attend in person at the RPU Service Center Community Room.

• **View Meeting: YouTube, Teams, Livestreaming**

- The meeting can be livestreamed or viewed after the meeting on YouTube via this link: **YouTube**

- Join the Teams meeting (livestream) by copying this link into a web browser: **Teams**

- A video of the meeting will be available on the City website to view following the meeting

• **Calling In to the Teams Meeting:**

- Call: 1-347-352-4853

- Conference ID: 102 738 21#

- Press *6 to mute and unmute your phone

• **In Person Attendance:**

- Attend the meeting in person at the RPU Service Center, Community Room

- Spacing is limited, so electronic attendance is encouraged

- The In-Person Open Comment Period is open to the public, however space is limited

Call to Order

1. Approval of Agenda

2. Safety Moment

3. Consent Agenda

1. Public Utility Board - Regular Meeting - May 25, 2021 4:00 PM
2. Review of Accounts Payable
3. Country Club Manor Standpipe Repair/Repainting

   Resolution: Country Club Manor Standpipe Repair/Repainting
4. Watermain & Sanitary Sewer Reconstruction (20th Street NW)

   Resolution: Watermain & Sanitary Sewer Reconstruction (20th Street NW)
5. Authorized Banking Representative

   Resolution: Authorized Banking Representative

NEW BUSINESS

Open Comment Period
(This agenda section is for the purpose of allowing citizens to address the Utility Board. Comments are limited to 4 minutes, total comment period limited to 15 minutes. Any speakers not having the opportunity to be heard will be the first to present at the next Board meeting.)

4. Regular Agenda

1. Cascade Creek Controls Upgrade Project (GT1)

   Resolution: Cascade Creek Controls Upgrade Project (GT1)
2. Distributed Energy Resources, Technical Specification Manual

   Resolution: Distributed Energy Resources, Technical Specification Manual
3. 2021 Electric Service Rules and Regulations

   Resolution: 2021 Electric Service Rules and Regulations
4. Board Committee Assignments

5. Informational

1. Strategic Planning

6. Board Liaison Reports

1. Adjustment of Utility Services Billed Policy

   Resolution: Adjustment of Utility Services Billed Policy
2. RPU Index of Board Policies

7. General Managers Report

8. Division Reports & Metrics

1. Division Reports & Metrics - June 2021

9. Other Business

10. Adjourn

The agenda and board packet for Utility Board meetings are available on-line at www.rpu.org and http://rochestercitymn.iqm2.com/Citizens/Default.aspx

MEETING MINUTES – MAY 25, 2021

COMMUNITY ROOM
4000 EAST RIVER ROAD NE
ROCHESTER, MN 55906

4:00 PM

This meeting will be conducted pursuant to Minnesota Statutes Section 13D.021 and members may appear electronically. Public access is closed to comply with state health guidance during the pandemic. When calling in by phone, join the meeting via the Microsoft Teams dial-in number listed below. Please remember to mute your phone until it is your turn to speak; press *6 to mute and unmute your phone.

The meeting will be live-streamed at the following web addresses: YouTube and Teams

In addition, a recording will be available after the meeting on the City's website.

Dial-In Number: 347-352-4853. Conference ID: 102 738 21#.

Call to Order

Attendee Name	Title	Status	Arrived
Brett Gorden	Board Member	Present	
Patrick Keane	Board Member	Present	
Tim Haskin	Board Member	Present	
Melissa Graner Johnson	Board Vice President	Present	
Brian Morgan	Board President	Present	

1. Approval of Agenda

1. **Motion to:** approve the agenda as pressented

RESULT:	**APPROVED [UNANIMOUS]**
MOVER:	Melissa Graner Johnson, Board Vice President
SECONDER:	Patrick Keane, Board Member
AYES:	Gorden, Keane, Haskin, Johnson, Morgan

2. Recognition: Jon Lenn

Lead Distribution Water Worker Jon Lenn was recognized for his 24 years of service to RPU by General Manager Mark Kotschevar and the RPU Board.

3. Safety Moment

Board Member Patrick Keane spoke regarding fire prevention and fire safety during the summer season.

4. Consent Agenda

1. Public Utility Board - Regular Meeting - Apr 27, 2021 4:00 PM
2. Review of Accounts Payable
3. Annual Cayenta Maintenance

   BE IT RESOLVED by the Public Utility Board of the City of Rochester, Minnesota, to approve payment of the invoice to N. Harris Computer Corporation in the amount of $183,860.74, plus applicable tax, for annual maintenance and support.

   Passed by the Public Utility Board of the City of Rochester, Minnesota, this 25th day of May, 2021.

   Resolution: Annual Cayenta Maintenance

4. **Motion to:** approve the consent agenda as presented

RESULT:	**APPROVED [UNANIMOUS]**
MOVER:	Tim Haskin, Board Member
SECONDER:	Brett Gorden, Board Member
AYES:	Gorden, Keane, Haskin, Johnson, Morgan

NEW BUSINESS

Open Comment Period

(This agenda section is for the purpose of allowing citizens to address the Utility Board. Comments are limited to 4 minutes, total comment period limited to 15 minutes. Any speakers not having the opportunity to be heard will be the first to present at the next Board meeting.)

President Morgan and Vice President Johnson both noted they did not receive the two emails included in the public comments in the board packet that came in through the RPU Board mailbox. Corporate Services Director Peter Hogan said he would put in a help ticket and follow up with IT on this. President Morgan opened the meeting for public comment. No one came forward to speak.

5. Consideration Of Bids

1. Marion Road Substation Site Grading, Excavation and Fence

   Two bids were received and opened on May 10, 2021 for the site grading, excavation and fence work for the new Marion Road Substation. The station will serve additional load growth in south Rochester and downtown, as well as provide service to Mayo Clinic. Carl Bolander & Sons, LLC was the low bidder for the project at $1,032,690. Materials Manager Andrew Bianco stated that staff is seeing widespread cost increases and a limited pool of qualified local contractors to perform such work. This project is included in RPU's 2021 capital budget. The project is expected to begin on June 1, 2021 and will be completed in the second quarter of 2022.

   Board Member Patrick Keane asked if the bids received were in line with expected costs. Manager of Electric Construction and Maintenance Neill Stiller said the bids were 25%-30% higher than the engineering estimate provided by RPU's consultant, which was $875,000-$900,000, however the cost is not out of line with what is being seen in the current environment.

   Board Member Tim Haskin asked about the size of the parcel being graded and fenced. It is just over six acres, said Mr. Stiller. What is the percentage of grading *work versus fence work, asked Mr. Haskin. The fence is less than $100,000 total cost, therefore the grading makes the bulk of the cost, said Mr. Stiller.*

Mr. Keane stated he is not surprised at the increased costs due to the pandemic and supply chain issues, but is fully in support of this project.

President Morgan asked if higher prices will cause a downstream effect and the need to slow down other projects in the capital plan, affecting the 2021 and 2022 budgets.
General Manager Mark Kotschevar said an analysis will be done as part of the budget planning process to determine what projects can be completed this year and what projects will carry over to next year.

Resolution: Marion Road Substation Site Grading, Excavation and Fence

BE IT RESOLVED by the Public Utility Board of the City of Rochester, Minnesota, to approve a contract agreement with Carl Bolander & Sons, LLC., in the amount of $1,032,690.00, authorize the RPU Project Manager to perform the acts necessary to execute the project, and authorize the Mayor and the City Clerk to execute the agreement for Marion Road Substation Site Grading, Excavation and Fence.

Passed by the Public Utility Board of the City of Rochester, Minnesota, this 25th day of May, 2021.

RESULT:	**ADOPTED [UNANIMOUS]**
MOVER:	Melissa Graner Johnson, Board Vice President
SECONDER:	Patrick Keane, Board Member
AYES:	Gorden, Keane, Haskin, Johnson, Morgan

6. Regular Agenda

1. Election of Officers

President Morgan called for nominations for the offices of board president and board vice president. Board member Patrick Keane nominated Melissa Graner Johnson as board president. Ms. Johnson accepted the nomination. President Morgan nominated Brett Gorden as board vice president. Mr. Gorden accepted the nomination. Board Member Tim Haskin moved to accept the nominations of Melissa Graner Johnson to the office of president, the nomination of Brett Gorden to the office of vice president and the appointment of Christina Bailey to the role of board secretary. Patrick Keane seconded the motion. Motion passed. Board members thanked Brian Morgan for his service as board president. President Morgan stated it has been an honor to serve.

2. Billing, Credit and Collections Policy

Director of Corporate Services Peter Hogan presented a request to revise the utility's Billing, Credit and Collections Policy to modify the commercial customer accounts deposit amount calculation, modify late fees, and to defer implementation of the late fee until April 15, 2022.

The deposit calculation for commercial customers will be modified to consist of the two highest month's bills from the previous 12 months at the service address. The late fee will be modified to a 1% charge of the average outstanding balance for the billing period or $5, whichever is greater, with no late fee charged on *balances of $20 or less. Late fees will also be delayed until April 15, 2022 following the end of the cold weather rule and allowing customers additional time to get caught up on payment plans.*

Board Member Patrick Keane asked if there are any utility constraints stipulating that the fee structure has to be supported by utility cost, policy-wise, or if this is just business practice. The utility charter and board policy determine rate structure, and fees reflect the cost to the utility at some level, but RPU does not aim to shift those costs to other customers, which is why late fees become necessary, said Mr. Hogan. Mr. Keane asked if the penalties have to reflect the cost. There is no policy stating that fees have to be tied to an actual calculation, said Mr. Hogan.

Vice President Johnson asked if the deferral of the late fee implementation needs to be added to the resolution. That language can be found in the resolution for the transition to normal operations, Mr. Hogan stated.

President Morgan stated he supports the policy changes as long as it strikes the right balance in not being overly or under punitive and the fiscal health of the utility is maintained.

Resolution: Billing, Credit and Collections Policy

BE IT RESOLVED by the Public Utility Board of the City of Rochester, Minnesota, to approve the amended Billing, Credit and Collections Policy.

Passed by the Public Utility Board of the City of Rochester, Minnesota, this 25th day of May, 2021.

RESULT:	**ADOPTED [UNANIMOUS]**
MOVER:	Melissa Graner Johnson, Board Vice President
SECONDER:	Patrick Keane, Board Member
AYES:	Gorden, Keane, Haskin, Johnson, Morgan

3. RPU Transition to Normal Operations

RPU is initiating a plan to return to normal operations with an action plan to transition back to performing electric disconnects by August 2, 2021, which has been authorized by the Public Utilities Commission as the date for investor owned utilities to resume disconnects for nonpayment. Late fees will be waived until April 2022, and will not be charged unless a payment arrangement has not been made or has been broken. RPU customer service reps will be flexible to each customer's unique situation in extending payment arrangements.

The average past due amount for RPU residential customers has increased from $153 on February 29, 2020 to $414 on April 30, 2021, said Director of Corporate Services Peter Hogan. RPU will continue its customer outreach effort to work with delinquent customers to establish a payment plan spread over 12 months to bring past due amounts current, and will go beyond 12 months in exceptional circumstances.

Director of Customer Relations Krista Boston said the customer service reps are working to reach out to as many people as possible and will work with each customer to solve unique problems and extenuating circumstances. Waiving late fees will help delinquent customers get caught up over the next ten months and give those who qualify the opportunity to apply for available assistance. State and federal programs have been slow in rolling out, said Ms. Boston, with the

Rent Help Minnesota program available but payments not yet made to applicants. Two programs offered by the state, a rent utility assistance program for those not yet delinquent and a homeowners assistance program for those unable to make mortgage and utility payments, have yet to be made publicly available. Currently the only assistance programs available to RPU customers are energy assistance which only covers electricity, and limited funds from the county emergency system.

Board member Patrick Keane asked if a great number of disconnects are anticipated. The majority of customers react quickly and will establish a payment plan before being disconnected, said Mr. Hogan. What if a customer is current on their current bill but have previous past dues, asked Mr. Keane. Working out a payment arrangement for the past due amount will avoid a customer disconnect, said Mr. Hogan. Mr. Keane asked about the current forecast for bad debt. Mr. Hogan said that RPU is anticipating nearly double the normal amount of bad debt.

Board Member Tim Haskin thanked customer service staff for the customer calls and outreach.

Resolution: RPU Transition to Normal Operations

BE IT RESOLVED by the Public Utility Board of the City of Rochester, Minnesota, to approve a return to normal operations as authorized by the Billing Credit and Collections Policy on August 2, 2021, with the exception of the Late Payment Fee which will be deferred until April 15, 2022.

Passed by the Public Utility Board of the City of Rochester, Minnesota, this 25th day of May, 2021.

RESULT:	**ADOPTED [UNANIMOUS]**
MOVER:	Patrick Keane, Board Member
SECONDER:	Melissa Graner Johnson, Board Vice President
AYES:	Gorden, Keane, Haskin, Johnson, Morgan

7. Informational

1. AMI Business Case

RPU has been looking into AMI (Advanced Metering Infrastructure) technology for over ten years, said General Manager Mark Kotschevar, and is now assessing its metering system for implementation of AMI (smart meters).

Tara Turch, project manager at ESource, a utility consulting firm hired by RPU, introduced to the board Dale Pennington, President of the Technology, Planning and Implementation consulting division of ESource (TPI), Mark Hatfield, Vice President of Innovation at TPI, and Jon Mitchell, consultant at TPI. The team presented a business case that models five different AMI scenarios. Currently, RPU uses a drive-by meter reading system to collect monthly water and electric reads for billing from radios attached to meters. Vendor support for drive-by meter reading is declining, stated Ms. Turch. Additionally, over 30% of electric meters are electromechanical and prone to under-registration and water meter radios are currently at the end of or past their life expectancy.

Mr. Mitchell presented the five proposed AMI scenarios to the board. Scenario 0 represents "Status Quo," in which RPU continues its current operational norms and invests money into maintaining the current drive-by metering system.

Scenario 1 "Unified Network" utilizes a single network to accommodate both electric and water services, with all electric meters exchanged for new meters that communicate through a shared network.

Scenario 2a "Independent Networks" is having separate networks for electric and water services and replacing all non-bridge electric meters with bridge meters. The electric meters would share a network and the water meters would share a network.

Scenario 2b "Electric-Only Network" incorporates AMI meters only for the electric meters, and the water meters would remain in the drive-by system.

Scenario 3 "Hybrid Migratory" is a system in which bridge meters will share a separate network, and the non-bridge meters and the water meters will share a single unified network. Over time, the bridge meters would be slowly transitioned onto the single unified network.

After some analysis, RPU chose to focus on Scenario 1, since it provides the highest return on investment (ROI), provides equity of service to all customers and has the simplest architecture in terms of implementation.

Mr. Mitchell stated that Scenario 1 financial metrics show the total capital expenditure for implementation to be $22.18 million for the base case (with a 20 year lifespan) and will have a payback period of 13 years. Benefits returned to the utility over the 20 year period would be approximately $38.89 million.

Mr. Hatfield shared the strategic advantages of AMI. It provides flexibility for future rates using data from the meters, for example, Time of Use (TOU) rates, demand rates, coincident peak rates and distributed energy rates. It also minimizes meter inventory impacts and the need for field exchanges. Further, the use of AMI smart meters is becoming an essential customer service, operational and optimization system for modern, efficient utilities. Under Scenario 1, RPU can achieve these benefits with an additional $9.3 million (in the base case), said Mr. Hatfield. He pointed out that even without AMI, RPU will need to spend $12.9 million to maintain its current metering operations, with none of the benefits provided.

General Manager Mark Kotschevar stated, following review of this study, staff recommends the board authorize proceeding to the next step to prepare a request for proposal for the procurement of AMI and Meter Data Management (MDM) systems, which will be brought back to the board at a future date for discussion.

Board Member Patrick Keane asked if the project could be piloted in certain areas to gain experience, or if a firm commitment is required. RPU could pilot the project, or do a proof of concept, but with 95,000 meters to convert, it is not a short term project and will take three to four years of conversion, said Mr. Kotschevar. Mr. Keane asked about real-life implementation and the changing technologies over the four year period. Launching an AMI project is a very structured process, said Mr. Pennington, and a proof of concept is set up when a vendor is selected. During that proof of concept, testing and integration is happening over the course of a year, where new work flows and new processes are built, and personnel are trained to respond directly to the information that is coming through the system. After that point, when all of the integration and connection points between the meters and the field are established, the meters are rolled out.

President Morgan asked how system upgrades will be performed and when the system would become obsolete. Mr. Pennington stated that AMI meters are exceptionally stable and there are systems that are 14 or 15 years old that are just now being replaced. Meter firmware and software are constantly being upgraded over the air with no site visits required, he said.

Vice President Johnson asked the ESource team if there are any concerns about price increases over the base capital expenditures in today's market conditions. The proposals have come from pricing and bidding data from the past month, so they reflect a very timely and accurate cost projection, said Mr. Pennington. Might there be any subsidies or incentives in implementing AMI from the president's infrastructure stimulus plan, asked Ms. Johnson? There has been on the water side with aging water infrastructure but not on the electric side, said Mr. Pennington. All available grants or funding opportunities will be pursued, said Mr. Pennington. How old are the water meters now, asked Ms. Johnson? There are at least 18,000 meters in the RPU system that are 20 years or older (roughly half), said Mr. Kotschevar.

President Morgan asked if demand response dollars have been factored into the ROI. No, said Mr. Kotschevar, as that is additional add-on technology, but there are other demand response options, such as the air conditioner control which can probably be done cheaper with the smart thermostat program rather than through direct load control using the AMI system. President Morgan asked if the AMI system will enable RPU to get further down the 100% renewable energy path. It offers an unlimited amount of rate options to incent demand response, allowing the customer to choose a rate structure and the flexibility to implement new rate tariffs down the road, Mr. Kotschevar stated.

Board Member Brett Gorden asked if the new metering technology and data management creates any cyber security risks. The meter data uses state of the art encryption methodology, said Mr. Pennington, and there is a firewall on the SCADA system, with data being offloaded through a firewall. The AMI does not have any conductivity through distribution directly.

Vice President Johnson and President Morgan both stated their support of this proposal. Mr. Kotschevar stated there will have to be internal discussions around funding this project so as to not place a financial burden on the utility. Staff will work during the budget process this year to determine the financial impacts, said Mr. Kotschevar, and will return to the board with updates.

8. Board Liaison Reports

Director of Corporate Services Peter Hogan stated the revised Billing, Credit and Collections policy will be brought back to the board for review and approval next month.

9. General Managers Report

General Manager Mark Kotschevar and President Morgan thanked departing City Attorney Jason Loos for his service to the RPU Board. Assistant City Attorney Michael Spindler-Krage will serve as interim City Attorney to the board.

The City Council has made a decision on the proposed downtown district energy heating system. The City plans to extend piping to connect all existing City buildings to share heating and cooling resources, which will be managed by the City, but will not build a stand alone energy plant to feed that system. If in the future, the City, County or a private developer adds more buildings, that may precipitate the need for a district energy plant and at that point RPU may become involved, said Mr. Kotschevar.

Mr. Kotschevar, Director of Customer Relations Krista Boston and President Morgan will attend the in-person APPA National Conference in June and other board members are invited to attend.

The Energy Conservation and Optimization Act, or ECO Act, passed and was signed into law by Minnesota Governor Tim Walz. Mr. Kotschevar said RPU will incorporate the changes to the conservation program and take advantage of some of the opportunities the revised program will provide to reduce customers' energy bills.

10. Division Reports & Metrics

No discussion.

11. Other Business

President Morgan stated that newly-elected President Johnson will reach out to perform Mr. Kotschevar's performance assessment.

Board committee assignments were discussed. Vice President Johnson suggested Brett Gorden move to the Finance committee and Brian Morgan move back to Strategic Planning. It was suggested that Patrick Keane assume the open position on the Rates committee. This item will appear on the June board agenda.

Mr. Kotschevar asked if the board would prefer that the June board meeting remain virtual or return to in-person attendance. The RPU community room would be set up to maintain social distancing. Board Member Tim Haskin asked if a hybrid meeting is possible. City Attorney Jason Loos stated that hybrid meetings are possible, however it usually creates a technology issue. After discussion, it was decided that the June board meeting will be an in-person meeting.

12. Adjourn

The agenda and board packet for Utility Board meetings are available on-line at www.rpu.org and http://rochestercitymn.iqm2.com/Citizens/Default.aspx

Submitted by:

____
Secretary

Approved by the Board

____
Board President

____
Date

FOR BOARD ACTION

Agenda Item # **(ID # 13510)** **Meeting Date: 6/29/2021**

SUBJECT: Review of Accounts Payable

PREPARED BY: Colleen Keuten

ITEM DESCRIPTION:

UTILITY BOARD ACTION REQUESTED:

ROCHESTER PUBLIC UTILITIES
A/P Board Listing By Dollar Range
For 05/11/2021 To 06/13/2021

Consolidated & Summarized Below 1,000

Greater than 50,000 :

SOUTHERN MN MUNICIPAL POWER A	May SMMPA Bill	7,017,361.90
MN DEPT OF REVENUE	April Sales and Use Tax	623,489.18
CONSTELLATION NEWENERGY-GAS D	April Gas for SLP	214,271.79
DOUGHERTY, MOLENDA, SOLFEST,	Cane Settlement Payment	205,000.00
N HARRIS COMPUTER CORP	Cayenta Renewal 7/1/21-6/30/22	196,501.18
A & A ELECT & UNDERGROUND CON	Directional Boring 48th Street NW	174,950.00
S L CONTRACTING INC	Watermain Reconstruction Teton	170,854.23
KFI ENGINEERS	Marion Rd Duct Bank Design	153,026.40
VEIT & CO INC (CONSTRUCTION)	Hydro Trash Rack	144,388.13
NEW AGE TREE SERVICE INC	614 Tree Clearance	135,335.81
A & A ELECT & UNDERGROUND CON	2017-2022 Directional Boring	108,811.89
MN DEPT OF HEALTH	Community Water Supply Fee April-June 2021	96,828.00
EPLUS TECHNOLOGY INC	IP System Equipment for Substations	86,170.10
CONSTELLATION NEWENERGY-GAS D	April Gas for Westside Energy	81,651.80
ASPLUNDH TREE EXPERT LLC (P)	Hourly Tree Trimming	65,618.79
OSI - OPEN SYSTEMS INTERNATIO	OSI SCADA System Ugrade	63,775.23
ADVANTAGE DIST LLC (P)	4015GAL-Oil, WES, Chevron HDAX 5200 SAE	59,173.32
ULTEIG ENGINEERS INC	Marion Rd Sub Proposal (3001,7001,8601)	53,927.00
CONSTELLATION NEWENERGY-GAS D	April Gas for Cascade Creek	52,392.36
	Price Range Total:	9,703,527.11

5,000 to 50,000 :

PAYMENTUS CORPORATION	April Credit/Debit/ACH Processing Fees	48,133.18
CENTRAL MINNESOTA MUNICIPAL P	May Capacity	37,400.00
BORDER STATES ELECTRIC SUPPLY	2EA-Meter, Primary Cab, 600 AMP With PT/	33,456.43
DOXIM UTILITEC LLC	May Bill Print/Mail Services/Postage	25,797.94
ELCOR CONSTRUCTION INC	Watermain Reconstruction	25,356.60
USIC HOLDINGS INC	May Locating Services	24,827.38
KEY BUILDERS INC	Facilities Office Renovations	20,078.00
EPLUS TECHNOLOGY INC	Closet Switch Replacement SC	20,006.27
N HARRIS COMPUTER CORP	Cayenta Caystone Testing	19,500.00
ENERSYS INC	60EA-Battery, 120V	18,237.15
US BANK - VOYAGER	May Fuel	17,520.64
PEOPLES ENERGY COOPERATIVE (P	May Territory Compensation	16,186.14
VISION COMPANIES LLC (P)	Employee Development	15,787.50
WIESER PRECAST STEPS INC (P)	3EA-Vault, Pulling, Straight-Thru	14,649.00
THE FENCE PROS LLC (P)	Service Center Fence	13,775.00
ZUMBRO EVANGELICAL LUTHERAN C	CIP-VSDs-Incntivs/Rebates	13,400.00
CENTURYLINK (P)	21 Monthly Telecommunications	13,304.79
MAYO CLINIC	CIP-VSDs-Incntivs/Rebates	13,244.98
KANTOLA CONSULTING	Cayenta, Time of Use & SEW Project Meetings	12,960.00
MIDCONTINENT ISO INC	May MISO Fees	12,890.87
SPECTRUM PRO-AUDIO dba	Community Room Microphone/AV Project	11,836.00
STELLA-JONES CORPORATION	9EA-Pole, 50ft, WRC, CL H1	11,610.00
ZUMBRO EVANGELICAL LUTHERAN C	CIP-Lighting (C&I)-Incentives/Rebates	11,604.00
PW POWER SYSTEMS INC	GT Borescope Inspection Services	11,003.06

ROCHESTER PUBLIC UTILITIES

A/P Board Listing By Dollar Range

For 05/11/2021 To 06/13/2021

Consolidated & Summarized Below 1,000

EPLUS TECHNOLOGY INC	SCADA Network Replacement	10,450.32
PW POWER SYSTEMS INC	40EA-Filter, Element, CT116793-SP1	10,364.31
WELLS FARGO BANK ACCT ANALYSI	May 2021 Bank Fees	10,045.26
MINNESOTA ENERGY RESOURCES CO	April Gas-Westside Energy	9,998.99
GLOBAL RENTAL COMPANY INC	Truck Rental-Altec AT41M Aerial Device	9,618.75
FORBROOK LANDSCAPING SERVICES	Replace Trees at Service Center	9,444.38
CITY OF ROCHESTER	CIP-VSDs-Incntivs/Rebates	8,099.25
VIKING ELECTRIC SUPPLY INC	1140FT-Conduit, PVC Sch 40, 4.00	7,811.28
ADVANTAGE DIST LLC (P)	5007GAL-Urea 32, WES	7,810.92
PREMIER ELECTRICAL CORP dba	Electrical Fixture Remodel	7,629.00
PARAGON DEVELOPMENT SYSTEMS I	21 Technical Support Services	7,605.00
N HARRIS COMPUTER CORP	Round Up Configuration.BI Task Moved to Prod	7,410.00
VIKING ELECTRIC SUPPLY INC	2800FT-Conduit, PVC Sch 40, 2.00	7,268.24
CONSOLIDATED COMMUNICATIONS d	2018-21 Network and Co-location Services	7,099.40
GRAYBAR ELECTRIC COMPANY INC	20EA-Grd Sleeve, 3ph Sect. Encl, 18 x 67	7,012.80
SCHMIDT GOODMAN OFFICE PRODUC	Facilities & IT Furniture	6,991.30
VENTURE PRODUCTS INC	Ventrac Tractor P690-Mower Attachment	6,561.52
CITY OF ROCHESTER	Medical Services	6,141.00
EPLUS TECHNOLOGY INC	IP System Equipment for Substations	6,085.27
QUADIENT INC	Acct# 7900 0440 8067 0809-Postage	6,000.00
CABLE TECHNOLOGY LABORATORIES	Cable Analysis	5,780.00
WESCO DISTRIBUTION INC	20000FT-Wire, Tracer, Orange, #12, CCS	5,640.00
ELEVATE MARKETING SOLUTIONS L	2021 Advertising	5,560.00
NALCO COMPANY LLC	1DRM-Rinse, Resin, NALCO 7293.15 (DEMIN)	5,502.31
VERIZON WIRELESS	2021 Cell & IPad Monthly Service	5,406.86
ARCHKEY TECHNOLOGIES dba	Community Room AV Project	5,292.00
NEW AGE TREE SERVICE INC	Trim trees @ CC	5,236.88
TWIN CITY SECURITY INC	2021 Security Services	5,194.12
STUART C IRBY CO INC	23130FT-Wire, ACSR, #4, 6/1, Swan	5,088.60
E SOURCE COMPANIES LLC	Professional Services	5,045.00
POWER PRODUCTS & SERVICES	1EA-Air Register Drives 1, 2 & 3, JD	5,040.23
ELITE EXTERIOR SOLUTIONS	SLP Building Wash	5,000.00
	Price Range Total:	685,797.92

1,000 to 5,000 :

WIESER PRECAST STEPS INC (P)	1EA-Vault, Pulling, 90 deg	4,883.00
CENTURY FENCE CO INC	Fence and Gate Install Cascade Creek	4,760.00
POMPS TIRE SERVICE INC	Replace 4 Tires	4,734.57
EPLUS TECHNOLOGY INC	4EA-10GBASE-LR SFP MODULE	4,714.36
EPLUS TECHNOLOGY INC	Phone Update for PCI Compliance	4,664.00
FORBROOK LANDSCAPING SERVICES	Landscaping Svcs (Electric)	4,543.47
ELITE CARD PAYMENT CENTER	OATI Web Cares Certificates	4,500.00
ULTEIG ENGINEERS INC	21 Engineering T&D	4,471.50
VIKING ELECTRIC SUPPLY INC	880FT-Conduit, PVC Sch 40, 3.00	4,373.07
THRONDSON OIL & LP GAS CO	Tanker Rental for ZRS Project	4,146.75
MINNESOTA ENERGY RESOURCES CO	April Gas-SLP	4,098.50
CENTURY FENCE CO INC	Barrier Gate Install	4,018.50
GOPHER STATE ONE CALL	Completed Tickets	3,942.00

ROCHESTER PUBLIC UTILITIES
A/P Board Listing By Dollar Range
For 05/11/2021 To 06/13/2021
Consolidated & Summarized Below 1,000

101	ARCHKEY TECHNOLOGIES dba	IT Cabinet Install	3,894.00
102	WSB & ASSOCIATES	Wetland Delineation Services	3,884.50
103	N HARRIS COMPUTER CORP	Round Up Documentation Configuration	3,802.50
104	HAWKINS INC	40EA-Chlorine Gas	3,785.00
105	HAWKINS INC	9947LB-Hydrofluosilicic Acid	3,779.86
106	VIKING ELECTRIC SUPPLY INC	380FT-Conduit, PVC Sch 40, 5.00	3,677.75
107	EGAN COMPANY	WES Fire Alarm Testing	3,633.75
108	BURNS & MCDONNELL INC (P)	Rate Design and Consulting	3,622.35
109	WESCO DISTRIBUTION INC	10EA-Elbow, 15kV, 600A, NLB, 4/0 AL Comp	3,599.20
110	ARCHKEY TECHNOLOGIES dba	Facility Offices Security and Network	3,445.00
154	WESCO DISTRIBUTION INC	36EA-Deadend Recept, 15kV, 600A, NLB	3,419.64
111	ENERSYS INC	6EA-Battery, 24V	3,412.80
112	ROCHESTER HOTEL PARTNERS	CIP-Refrigerators-Incentives/Rebates	3,125.00
113	ROCHESTER CHEVROLET CADILLAC	Filter, Pipes, Nuts, Gaskets, Sensors	3,104.57
114	FORBROOK LANDSCAPING SERVICES	Landscaping Water Site	3,082.83
115	HAWKINS INC	330GAL-Carus 8500 Aqua Mag Phosphate	3,052.50
116	BAKER TILLY US, LLP	2018-2022 Audit Fees	3,040.00
117	CRESCENT ELECTRIC SUPPLY CO	3600FT-Wire, AL, 600V, #2-#4 ACSR NEU Tr	3,016.44
118	ROCHESTER HOTEL PARTNERS	CIP-Dishwashers-Incentives/Rebates	2,900.00
119	KNXR - FM	May Radio Ads	2,900.00
120	WINKELS ELECTRIC INC	18th Ave & 50th Street NW - Street Light	2,771.27
121	STUART C IRBY CO INC	2021 Rubber Goods Testing & Replacement	2,746.05
122	CLARK CONCRETE INC	Concrete for 4 Locations	2,732.79
123	BORDER STATES ELECTRIC SUPPLY	100EA-Elbow, 15kV, 200A, LB,1/0 Sol,175-	2,724.00
124	ARCHKEY TECHNOLOGIES dba	System Ops Lock Controls	2,595.99
125	ONLINE INFORMATION SERVICES I	May 2021 Utility Exchange Report	2,418.18
126	CORE & MAIN LP (P)	200EA-Riser, 1.50 Slip Type Riser (65-A)	2,410.00
127	PALMER SODERBERG INC	Ceiling - Facilities Office	2,400.00
128	IHEART MEDIA dba	April Radio Ads	2,400.00
129	BADGER PAINTING	Tape & Paint for Office Build Out Project	2,390.79
130	BOLTON AND MENK (P)	TMOB Baihly #92 Telecom Modifications	2,362.50
131	BORDER STATES ELECTRIC SUPPLY	WES Lighting Protection System Materials	2,292.66
132	ARCHKEY TECHNOLOGIES dba	SLP Fiber Pull	2,274.30
133	CDW GOVERNMENT INC	2EA-TV, LED, 75"	2,232.00
134	STELLA-JONES CORPORATION	3EA-Pole, 45ft, WRC, CL3	2,205.00
135	VIKING ELECTRIC SUPPLY INC	3150FT-Wire, Copper, #6 SD Solid, Bare	2,189.19
136	GFL SOLID WASTE MIDWEST LLC	2021 Waste removal SC	2,163.46
137	ADVANTAGE DIST LLC (P)	Oil for Fleet	2,130.80
138	NALCO COMPANY LLC	1DRM-Sur-Gard 1700 Oxygen Scavenger DEMI	2,109.86
139	OPEN ACCESS TECHNOLOGY	2021 NERC Web Compliance Software	2,068.76
140	EPLUS TECHNOLOGY INC	CISCO DNA essentials 3 year	2,036.00
141	STELLA-JONES CORPORATION	2EA-Pole, 55ft, WRC, CL3	2,030.00
142	WSB & ASSOCIATES	Marion Road Wetland Delineation Services	2,000.00
143	WARNING LITES OF MN INC (P)	Warning Light Rental - 48th Street NW	1,996.00
144	REALIFE COOPERATIVE OF ROCHES	CIP-Lighting (C&I)-Incentives/Rebates	1,964.70
145	N HARRIS COMPUTER CORP	Configuration for Sales Tax Charges	1,950.00
146	STUART C IRBY CO INC	750FT-Conduit, Corrugated PVC, 3.00	1,950.00
147	NEW AGE TREE SERVICE INC	Trim Trees @ Well 35 - 41st Street	1,945.13
148	UNITED RENTALS INC	Boom Rental	1,815.81
149	BORDER STATES ELECTRIC SUPPLY	36KIT-Pedestal, Repair Kit	1,797.84

ROCHESTER PUBLIC UTILITIES
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150	HARRIS ROCHESTER INC (HIMEC)	2021 HVAC Maint Agreement	1,796.57
151	TECH SAFETY LINES	3EA-Self Rescue Kit, w/ 65' Line	1,763.44
152	KENNEDY & GRAVEN CHARTERED	Legal Services	1,740.55
153	DAVID SANNEMAN	CIP-Lighting (C&I)-Incentives/Rebates	1,732.50
154	BRIGHT CHRISTINE	CIP-AirSrc Heat Pumps-Incentives/Rebates	1,620.00
155	VIKING ELECTRIC SUPPLY INC	2000FT-Wire, Copper, 600V, 12-2 Solid w/	1,612.21
156	UNITED RENTALS INC	Boom Rental	1,600.52
157	S L CONTRACTING INC	WM Break Repair for 1406 10 Ave SE	1,583.00
158	VERIZON CONNECT NWF INC	May 2021 GPS Fleet Tracking	1,570.43
159	PALMER SODERBERG INC	Ceiling Repair Facilities	1,549.69
160	NEW AGE TREE SERVICE INC	East entrance @ RPU	1,539.00
161	TAW MIAMI SERVICE CENTER INC	2EA-Filter, WS Generato, Oil Filter Cart	1,525.00
162	U S A SAFETY SUPPLY	14EA-Shirt, FR, Hi-Vis	1,516.75
163	POWER SYSTEMS ENGINEERING INC	System Study and Transient Analysis	1,491.00
164	WARNING LITES OF MN INC (P)	Warning Lite Rental - 3101 Superior Drive	1,481.20
165	WESCO DISTRIBUTION INC	18EA-Terminator Cover, For CS Terminator	1,465.71
166	HUNT ELECTRIC CORP	Changeout of 2 Utility Transformers-Labor	1,457.50
167	WSB & ASSOCIATES	Easement Language & Exhibits-McDonalds P	1,453.50
168	STUART C IRBY CO INC	20EA-Arrester, 10kV, Dist, Elbow MOV	1,435.00
169	NARDINI FIRE EQUIPMENT CO INC	Semi Annual Inspection Mtls & Labor	1,420.50
170	WIESER PRECAST STEPS INC (P)	1EA-Grd Sleeve, Switch Basement, PME	1,355.00
171	BANKS JOSHUA C	Drone Inspect,Arbor Day,Main Break,etc-P	1,350.00
172	CUSTOM COMMUNICATIONS INC	2021 Custom Connect Monitor & Protective	1,341.24
173	GFL SOLID WASTE MIDWEST LLC	2021 Waste removal WES/CC	1,334.37
174	SCHMIDT GOODMAN	CIP-Lighting (C&I)-Incentives/Rebates	1,330.00
175	BOLTON AND MENK (P)	TMOB Rose Harbor Telecom Modifications	1,312.50
176	BARR ENGINEERING COMPANY (P)	General Groundwater Services	1,305.00
177	ALLIED VALVE INC	1EA-Transmitter, Tower, Rosemount 3051	1,305.00
178	ELITE CARD PAYMENT CENTER	CP Railroad Permit-Crossing for Fiberopt	1,294.00
179	CITY OF ROCHESTER	Workers Comp Fees April 2021	1,282.00
180	ELITE CARD PAYMENT CENTER	Registration Brian Morgan APPA	1,275.00
181	ELITE CARD PAYMENT CENTER	Registration MKotschevar APPA	1,275.00
182	EPLUS TECHNOLOGY INC	2021 Network maintenance services	1,272.00
183	EPLUS TECHNOLOGY INC	Network Essentials	1,271.79
184	NEW AGE TREE SERVICE INC	Trim trees @ WES	1,255.78
185	SCHMIDT GOODMAN OFFICE PRODUC	Shelving for Mail Room	1,254.79
186	HEWLETT PACKARD ENTERPRISE CO	Hard Drive 900GB,12G for SCADA Upgrade	1,227.99
187	STELLA-JONES CORPORATION	2EA-Pole, 40ft, WRC, CL3	1,216.00
188	ROCHESTER ARMORED CAR CO INC	2021 Pick Up Services	1,187.24
189	S L CONTRACTING INC	WM Break Repair	1,181.00
190	TMS JOHNSON INC	1EA-Fan, Exhaust	1,160.00
191	SANDSTROM KYLE	CIP-Geothermal (R)-Incentives/Rebates	1,156.00
192	ELITE CARD PAYMENT CENTER	100 Custom Patches	1,152.11
193	VIKING ELECTRIC SUPPLY INC	Micellaneous Parts for Truck 665	1,133.27
194	BRADEN FILTRATION LLC	120EA-Filter insert, Pre-filter	1,122.19
195	HATHAWAY TREE SERVICE INC	Brush Load	1,090.00
196	OPEN ACCESS TECHNOLOGY	June NERC Compliant tag agent	1,078.57
197	SOMA CONSTRUCTION INC	Materials for WM breaks	1,065.81
198	HINDT-KUISLE PEGGY	CIP-AirSrc Heat Pumps-Incentives/Rebates	1,055.00
199	BOLTON AND MENK (P)	TMOB Golden Hill Telecom Modifications	1,050.00

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BOLTON AND MENK (P)	TMOB John Adams Modifications	1,050.00
MCNEILUS STEEL INC	Fleet Material	1,034.53
VIKING ELECTRIC SUPPLY INC	Electrical Parts for Well Site 72	1,030.88
	Price Range Total:	264,288.62

0 to 1,000 :

Customer Refunds (CIS)	Summarized transactions: 150	19,496.39
REBATES	Summarized transactions: 77	14,657.53
EXPRESS SERVICES INC	Summarized transactions: 17	14,055.96
ELITE CARD PAYMENT CENTER	Summarized transactions: 47	12,895.39
U S A SAFETY SUPPLY	Summarized transactions: 26	5,356.06
WESCO DISTRIBUTION INC	Summarized transactions: 19	4,749.01
BOLTON AND MENK (P)	Summarized transactions: 8	4,550.00
STUART C IRBY CO INC	Summarized transactions: 19	4,270.06
MINNESOTA ENERGY RESOURCES CO	Summarized transactions: 7	3,231.69
BORDER STATES ELECTRIC SUPPLY	Summarized transactions: 12	3,159.60
GRAINGER INC	Summarized transactions: 21	3,018.26
CITY LAUNDERING COMPANY	Summarized transactions: 21	2,824.86
WERNER ELECTRIC SUPPLY	Summarized transactions: 35	2,583.37
EPLUS TECHNOLOGY INC	Summarized transactions: 4	2,344.86
MCMASTER CARR SUPPLY COMPANY	Summarized transactions: 41	2,239.55
CORE & MAIN LP (P)	Summarized transactions: 8	2,218.70
GARCIA GRAPHICS INC	Summarized transactions: 8	2,056.50
CHS ROCHESTER	Summarized transactions: 4	2,009.93
FIRST CLASS PLUMBING & HEATIN	Summarized transactions: 7	1,995.08
CENTURYLINK (P)	Summarized transactions: 12	1,961.02
TMS JOHNSON INC	Summarized transactions: 5	1,822.00
S L CONTRACTING INC	Summarized transactions: 2	1,807.00
LAWSON PRODUCTS INC (P)	Summarized transactions: 7	1,804.36
ENVIRONMENTAL SYSTEMS RESEARC	Summarized transactions: 2	1,800.00
CITY OF ROCHESTER	Summarized transactions: 9	1,795.29
ROCHESTER CHEVROLET CADILLAC	Summarized transactions: 10	1,688.24
ELITE CARD PAYMENT CENTER	Summarized transactions: 5	1,660.81
GDS ASSOCIATES INC	Summarized transactions: 2	1,642.50
DELL MARKETING LP	Summarized transactions: 6	1,632.67
G A ERNST & ASSOCIATES INC	Summarized transactions: 3	1,585.69
VIKING ELECTRIC SUPPLY INC	Summarized transactions: 15	1,583.24
ADVANTAGE DIST LLC (P)	Summarized transactions: 4	1,576.19
ADVANCE AUTO PARTS	Summarized transactions: 27	1,519.47
AMAZON.COM	Summarized transactions: 12	1,407.50
RESCO	Summarized transactions: 5	1,405.23
VIKING ELECTRIC SUPPLY INC	Summarized transactions: 8	1,383.69
SCHMIDT GOODMAN OFFICE PRODUC	Summarized transactions: 3	1,366.11
PW POWER SYSTEMS INC	Summarized transactions: 10	1,334.52
GFL SOLID WASTE MIDWEST LLC	Summarized transactions: 2	1,272.74
METRO SALES INC	Summarized transactions: 2	1,155.57
STAR ENERGY SERVICES LLC	Summarized transactions: 3	1,151.00
HARRIS ROCHESTER INC (HIMEC)	Summarized transactions: 3	1,148.98

ROCHESTER PUBLIC UTILITIES
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250	NORTHERN / BLUETARP FINANCIAL	Summarized transactions: 10	1,054.03
251	HALO BRANDED SOLUTIONS	Summarized transactions: 5	1,047.88
252	NUVERA	Summarized transactions: 2	1,003.26
253	FORBROOK LANDSCAPING SERVICES	Summarized transactions: 3	931.13
254	ERC WIPING PRODUCTS INC	Summarized transactions: 3	929.66
255	WSB & ASSOCIATES	Summarized transactions: 1	910.00
256	PEOPLES ENERGY COOPERATIVE	Summarized transactions: 3	908.36
257	OPTIV SECURITY INC	Summarized transactions: 1	905.81
258	CREDIT MANAGEMENT LP	Summarized transactions: 2	900.43
259	NEXT DOOR	Summarized transactions: 1	890.27
260	IMAGEBRIDGE DESIGN	Summarized transactions: 1	890.00
261	MAILE ENTERPRISES INC	Summarized transactions: 3	886.47
262	ON SITE SANITATION INC	Summarized transactions: 2	875.43
263	A T & T	Summarized transactions: 1	874.71
264	UNITED RENTALS INC	Summarized transactions: 5	869.32
265	ENERSYS INC	Summarized transactions: 4	862.07
266	RONCO ENGINEERING SALES INC	Summarized transactions: 3	860.51
267	FORBROOK LANDSCAPING SERVICES	Summarized transactions: 1	829.43
268	A & A ELECT & UNDERGROUND CON	Summarized transactions: 1	820.00
269	MANTHEI SEPTIC SERVICE	Summarized transactions: 1	800.00
270	ROCHESTER SWEEPING SERVICE LL	Summarized transactions: 1	800.00
271	CITY OF ROCHESTER	Summarized transactions: 5	783.77
272	MAYO CIVIC CENTER	Summarized transactions: 1	776.00
273	BLUESPIRE dba	Summarized transactions: 1	775.35
274	CORPORATE WEB SERVICES INC	Summarized transactions: 2	775.34
275	CORE & MAIN LP (P)	Summarized transactions: 3	774.58
276	VENTURE PRODUCTS INC	Summarized transactions: 1	763.80
277	THE ENERGY AUTHORITY INC	Summarized transactions: 1	753.80
278	USA BLUE BOOK DBA	Summarized transactions: 4	739.05
279	NAPA AUTO PARTS dba	Summarized transactions: 6	733.93
280	CENTURYLINK	Summarized transactions: 1	718.62
281	MENARDS ROCHESTER NORTH	Summarized transactions: 5	715.74
282	LEAGUE OF MN CITIES INS TRUST	Summarized transactions: 1	713.84
283	MN VALLEY TESTING LABS INC	Summarized transactions: 1	710.50
284	ASPLUNDH TREE EXPERT LLC (P)	Summarized transactions: 2	708.89
285	CASTILLO ROB	Summarized transactions: 2	699.60
286	PETERSON CHAD	Summarized transactions: 2	699.60
287	RDO EQUIPMENT COMPANY (P)	Summarized transactions: 6	696.44
288	POLLARDWATER dba	Summarized transactions: 4	689.07
289	ROOT RIVER HARDWOODS INC	Summarized transactions: 3	670.38
290	MCNEILUS STEEL INC	Summarized transactions: 2	662.90
291	BARR ENGINEERING COMPANY (P)	Summarized transactions: 1	656.00
292	NETWORK SERVICES COMPANY	Summarized transactions: 5	653.35
293	INGERSOLL RAND COMPANY	Summarized transactions: 5	650.38
294	CITY LAUNDERING COMPANY	Summarized transactions: 4	620.26
295	HALLBERG ENGINEERING INC	Summarized transactions: 1	620.00
296	TRUCKIN' AMERICA	Summarized transactions: 1	615.60
297	LOCATORS AND SUPPLIES	Summarized transactions: 2	605.46
298	VIOLA NURSERY AND GREENHOUSE	Summarized transactions: 2	604.68
299	TECH SAFETY LINES	Summarized transactions: 2	602.66

Attachment: AP Board CrMo 05 2021 (13510 : Review of Accounts Payable)

ROCHESTER PUBLIC UTILITIES
A/P Board Listing By Dollar Range
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300	FASTENAL COMPANY	Summarized transactions: 13	597.78
301	POMPS TIRE SERVICE INC	Summarized transactions: 4	593.20
302	ARCHKEY TECHNOLOGIES dba	Summarized transactions: 1	589.00
303	ULTEIG ENGINEERS INC	Summarized transactions: 2	572.00
304	TOKAY SOFTWARE dba	Summarized transactions: 2	570.71
305	MISSISSIPPI WELDERS SUPPLY CO	Summarized transactions: 13	568.55
306	SOMA CONSTRUCTION INC	Summarized transactions: 1	561.46
307	WABASHA IMPLEMENT	Summarized transactions: 2	532.52
308	PARAGON DEVELOPMENT SYSTEMS I	Summarized transactions: 1	530.49
309	BOBCAT COMPANY dba	Summarized transactions: 3	512.32
310	SMART ENERGY SYSTEMS LLC	Summarized transactions: 1	505.33
311	AMERICAN PAYMENT CENTER	Summarized transactions: 1	500.00
312	INNOVATIVE OFFICE SOLUTIONS L	Summarized transactions: 6	489.90
313	KOTSCHEVAR MARK	Summarized transactions: 2	466.84
314	CRESCENT ELECTRIC SUPPLY CO	Summarized transactions: 7	451.13
315	HUNT ELECTRIC CORP	Summarized transactions: 1	451.06
316	LANGUAGE LINE SERVICES INC	Summarized transactions: 1	417.70
317	N HARRIS COMPUTER CORP	Summarized transactions: 1	390.00
318	NOVASPECT INC	Summarized transactions: 3	370.73
319	MSC INDUSTRIAL SUPPLY CO INC	Summarized transactions: 6	369.49
320	GREAT RIVER ENERGY	Summarized transactions: 2	364.81
321	ADVANCED DISPOSAL	Summarized transactions: 1	360.46
322	ROCH PLUMBING & HEATING CO IN	Summarized transactions: 1	349.45
323	NESCO LLC	Summarized transactions: 2	336.06
324	VERIZON WIRELESS	Summarized transactions: 2	334.38
325	U S PLASTIC CORP	Summarized transactions: 3	324.08
326	GOODIN COMPANY	Summarized transactions: 4	315.38
327	THOMAS TOOL & SUPPLY INC	Summarized transactions: 6	308.82
328	RONCO ENGINEERING SALES INC	Summarized transactions: 3	308.31
329	BRADEN FILTRATION LLC	Summarized transactions: 1	308.17
330	ZIEGLER INC	Summarized transactions: 4	296.70
331	MENARDS ROCHESTER NORTH	Summarized transactions: 5	295.42
332	HI LINE UTILITY SUPPLY CO (P)	Summarized transactions: 2	281.72
333	FASTENAL COMPANY	Summarized transactions: 4	275.42
334	ALL SEASONS POWER & SPORT INC	Summarized transactions: 1	267.14
335	CHARTER COMMUNICATIONS	Summarized transactions: 2	250.24
336	NALCO COMPANY LLC	Summarized transactions: 2	248.25
337	REINDERS INC (P)	Summarized transactions: 1	246.88
338	VANCO SERVICES LLC	Summarized transactions: 1	240.84
339	DAVE SYVERSON TRUCK CENTER IN	Summarized transactions: 2	240.63
340	JIM WHITING NURSERY/GARDEN CT	Summarized transactions: 1	240.00
341	WATER SYSTEMS COMPANY	Summarized transactions: 3	236.70
342	MENARDS ROCHESTER SOUTH	Summarized transactions: 3	233.10
343	ZEE MEDICAL SERVICE INC (P)	Summarized transactions: 4	229.33
344	BORENE LAW FIRM P.A.	Summarized transactions: 2	221.18
345	KRUSE LUMBER	Summarized transactions: 2	210.72
346	ALTERNATIVE TECHNOLOGIES INC	Summarized transactions: 1	195.00
347	FRONTIER	Summarized transactions: 1	193.21
348	DAKOTA SUPPLY GROUP	Summarized transactions: 1	178.50
349	HOGAN PETER	Summarized transactions: 2	174.60

ROCHESTER PUBLIC UTILITIES
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350	KAMAN INDUSTRIAL TECHNOLOGIES	Summarized transactions: 3	167.37
351	BECKLEYS OFFICE PRODUCTS INC	Summarized transactions: 1	155.00
352	CDW GOVERNMENT INC	Summarized transactions: 2	153.45
353	XTREAM MACHINE SOLUTIONS LLC	Summarized transactions: 1	151.88
354	FEDEX SHIPPING	Summarized transactions: 12	150.52
355	MN DEPT OF HEALTH	Summarized transactions: 1	150.00
356	ENERSYS INC	Summarized transactions: 3	147.10
357	PROPERTY RECORDS OLMSTED COUN	Summarized transactions: 2	146.00
358	SOUND AND MEDIA SOLUTIONS	Summarized transactions: 1	144.28
359	ARNOLDS SUPPLY & KLEENIT CO (	Summarized transactions: 4	135.47
360	FEDEX SHIPPING	Summarized transactions: 3	132.95
361	PLANT & FLANGED EQUIPMENT CO	Summarized transactions: 3	131.54
362	QUADIENT INC	Summarized transactions: 2	124.96
363	TAW MIAMI SERVICE CENTER INC	Summarized transactions: 2	113.55
364	GLOBAL RENTAL COMPANY INC	Summarized transactions: 3	112.50
365	A T & T MOBILITY	Summarized transactions: 4	106.78
366	CURVATURE INC	Summarized transactions: 1	104.74
367	MN DEPT OF LABOR & INDUSTRY	Summarized transactions: 1	100.00
368	BOSTON KRISTA	Summarized transactions: 1	91.59
369	BOWMANS SAFE & LOCK SHOP LTD	Summarized transactions: 3	89.06
370	MENARDS ROCHESTER SOUTH	Summarized transactions: 3	86.52
371	SLEEPY EYE TELEPHONE CO	Summarized transactions: 1	84.76
372	RAIN RICHARD	Summarized transactions: 1	79.99
373	VERIFIED CREDENTIALS INC	Summarized transactions: 1	77.00
374	FORUM COMMUNICATIONS COMPANY	Summarized transactions: 2	75.67
375	CHESNEY JAMES	Summarized transactions: 1	72.80
376	CLAREY'S SAFETY EQUIPMENT dba	Summarized transactions: 1	70.54
377	BROCK WHITE COMPANY LLC (P)	Summarized transactions: 1	68.93
378	CENTRAL FINANCE OLMSTED COUNT	Summarized transactions: 2	67.48
379	SOUTHERN MN AUTO SUPPLY INC	Summarized transactions: 1	61.05
380	T E C INDUSTRIAL INC	Summarized transactions: 2	52.71
381	MINNESOTA CONTINUING LEGAL ED	Summarized transactions: 2	51.30
382	MIDWEST RENEWABLE ENERGY TRAC	Summarized transactions: 1	50.82
383	U S BANK	Summarized transactions: 1	45.96
384	WIRKUS MIKE	Summarized transactions: 1	43.00
385	OLMSTED COUNTY 4-H COUNCIL	Summarized transactions: 2	40.00
386	DECOOK LANDSCAPING	Summarized transactions: 2	40.00
387	POWER PRODUCTS & SERVICES	Summarized transactions: 1	27.87
388	CENTER FOR ENERGY AND ENVIRON	Summarized transactions: 1	25.65
389	REBATES	Summarized transactions: 1	25.00
390	MINNESOTA ENERGY RESOURCES CO	Summarized transactions: 1	24.92
391	NORTH AMERICAN ELECTRIC RELIA	Summarized transactions: 1	23.72
392	BATTERIES PLUS	Summarized transactions: 1	23.41
393	POWER DYNAMICS INC dba	Summarized transactions: 5	23.30

Attachment: AP Board CrMo 05 2021 (13510 : Review of Accounts Payable)

FOR BOARD ACTION

Agenda Item # **(ID # 13508)** **Meeting Date: 6/29/2021**

SUBJECT: Country Club Manor Standpipe Repair/Repainting

PREPARED BY: Mona Hoeft

ITEM DESCRIPTION:

Sealed bids were opened on June 21, 2021 for repairing and repainting the 1,000,000 gallon Country Club Manor Standpipe to be completed by September 24, 2021. This work consists of interior and exterior finish repair and repaint. A breakdown of the bids is as follows:

Contractor	Bid Amount
JNB Industrial	$99,500
Maguire Iron	$196,150
Osseo Construction	$254,000
Champion Coatings	$254,500
M.K. Painting	$280,000
TMI Coatings	$311,000
Classic Coating	$342,600

JNB Industrial pulled their bid from consideration. This leaves Maguire Iron as the next lowest, responsible bidder. An estimated number of hours and rates for interior sealing have been included in the bid price indicated above. Hourly welding rates have also been obtained should it be needed. These hourly based tasks have the potential of increasing the contract amount, and these increases will be managed by existing approval structure and authorization levels. The 2021 Water Maintenance and Construction budget includes $280,000 for this project.

UTILITY BOARD ACTION REQUESTED:

Approve a resolution to accept the bid from Maguire Iron, Inc., in an amount not to exceed $196,150.

RESOLUTION

BE IT RESOLVED by the Public Utility Board of the City of Rochester, Minnesota, to accept the bid from Maguire Iron, Inc., in an amount not to exceed $196,150, for Country Club Manor Standpipe Repair/Repainting.

Passed by the Public Utility Board of the City of Rochester, Minnesota, this 29th day of June, 2021.

____

President

____

Secretary

FOR BOARD ACTION

Agenda Item # **(ID # 13499)** **Meeting Date: 6/29/2021**

SUBJECT: Watermain & Sanitary Sewer Reconstruction (20th Street NW)

PREPARED BY: Mona Hoeft

ITEM DESCRIPTION:

Sealed bids for the water main and sanitary sewer reconstruction project on 20th Street NW were received on June 10, 2021. The bid results, based on estimated unit pricing, are listed below.

Contractor	Bid
Snow Contracting, LLC	$417,057.11
Elcor Construction, Inc.	$507,390.00
SL Contracting Inc.	$557,400.00
Carl Bolander & Sons LLC	$634,368.90

This 2021 budgeted project will be performed jointly with Rochester Public Works (RPW) using the Utility Cost Methodology for Infrastructure Projects process. RPW is expected to contribute about $159,394 towards the project, plus contingency share. City Council approved RPW's share on June 21st.

Snow Contracting, LLC withdrew their bid leaving Elcor Construction as the lowest responsible bidder. The engineers estimate was $526,242. The RPU team is comfortable with Elcor's bid and this contractor has performed well in the past. At this time, the RPU team is also seeking approval of a contingency fund in the amount of $51,000 and authorizing the RPU Project Manager to perform the acts to execute the project.

This project was identified on the water system replacement priority list using the Water Main Replacement Analysis completed by HDR on March 5, 2019. There were a total of six water main breaks on this line and the water pressure for the homes in this area fall below our required minimum, so this bid includes making a main water connection between two pressure zones to correct this issue. This water main connection will also create looping for a currently dead end line to improve water quality. This project is expected to be complete no later than October 31, 2021.

UTILITY BOARD ACTION REQUESTED:

Approve a resolution to accept the bid from Elcor Construction, Inc. in an amount not to exceed $558,390 and authorize the RPU Project Manager to perform the acts to execute the project.

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RESOLUTION

BE IT RESOLVED by the Public Utility Board of the City of Rochester, Minnesota, to accept the bid from Elcor Construction, Inc. in an amount not to exceed $558,390 for Watermain and Sanitary Sewer Reconstruction at 20th Street NW and authorize the RPU Project Manager to perform the acts to execute the project.

Passed by the Public Utility Board of the City of Rochester, Minnesota, this 29th day of June, 2021.

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President

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Secretary

FOR BOARD ACTION

Agenda Item # **(ID # 13506)** **Meeting Date: 6/29/2021**

SUBJECT: Authorized Banking Representative

PREPARED BY: Peter Hogan

ITEM DESCRIPTION:

Financial institutions that are authorized to do business with Rochester Public Utilities (RPU), a division of the City of Rochester, require an approved resolution designating those employees of RPU authorized to conduct financial business on behalf of the Utility.

Julie Ackerman, Controller, resigned as of July 6, 2021, and as such will need to be removed as an authorized person to conduct financial transactions with our authorized depositories.

UTILITY BOARD ACTION REQUESTED:

Request the Board approve the updated schedule of authorized banking representatives for Rochester Public Utilities.

R E S O L U T I O N

BE IT RESOLVED by the Public Utility Board of the City of Rochester, Minnesota, that the following person or persons are hereby authorized for and on behalf of the City of Rochester, doing business as, Rochester Public Utilities, to endorse or cause to be endorsed such documents regarding deposits, checks, drafts, investments or any other matter necessary for or pertaining to the financial operation of Rochester Public Utilities.

Mark Kotschevar, General Manager

Peter Hogan, Chief Financial Officer

Melissa Braaten, Accounting Supervisor

Judy Anderson, Senior Financial Analyst

Tina Livingston, Senior Financial Analyst

Passed by the Public Utility Board of the City of Rochester, Minnesota, this 29th day of June, 2021.

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President

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Secretary

FOR BOARD ACTION

Agenda Item # **(ID # 13514)** **Meeting Date: 6/29/2021**

SUBJECT: Cascade Creek Controls Upgrade Project (GT1)

PREPARED BY: Tony Dzubay

ITEM DESCRIPTION:

Staff received a proposal from Petrotech Inc. to upgrade the Westinghouse control system for GT1 at Cascade Creek and is seeking approval to move this project forward. The cost of this project is $179,483 and is expected to take about six days. The proposal includes the purchase of equipment, spares and configuration services to upgrade or replace obsolete equipment such as the PLC Controller, HMI's, vibration monitor, and gas fuel flow Measurement. These controllers and modules are used to operate (start, stop, change load) and monitor every aspect of the turbine generator. The control PCs (HMIs) can control the turbine generator locally at Cascade Creek or remotely from SLP. A new control computer will be added as part of this project to the Westside control room for more versatility and operational coverage.

Continued investment in this machine is prudent given the revenue it will generate from the 10 year capacity sale approved last year. The RPU team is also seeking approval of a contingency fund in the amount of $18,000 and authorizing the RPU Project Manager to perform the acts to execute the project.

This project was planned and budgeted for 2021 and is within budgetary estimates.

UTILITY BOARD ACTION REQUESTED:

Subject to reaching agreement on the terms of the contract, approve a resolution to accept the proposal from Petrotech, Inc. in an amount not to exceed $197,483 and authorize the RPU Project Manager to perform the acts to execute the project.

RESOLUTION

BE IT RESOLVED by the Public Utility Board of the City of Rochester, Minnesota, to approve the proposal from Petrotech, Inc., subject to final agreement, for Cascade Creek Controls Upgrade Project (GT1) in an amount not to exceed $197,483 and authorize the RPU Project Manager to perform the acts to execute the project.

Passed by the Public Utility Board of the City of Rochester, Minnesota, this 29th day of June, 2021.

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President

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Secretary

FOR BOARD ACTION

Agenda Item # **(ID # 13438)** **Meeting Date: 6/29/2021**

SUBJECT: Distributed Energy Resources, Technical Specification Manual

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PREPARED BY: Steve Cook

ITEM DESCRIPTION:

In May 2019, the RPU Board adopted process documents and agreements for Distributed Energy Resource interconnections with the RPU electric distribution system that meet the State requirements and were based on documents created for the Minnesota Municipal Utilities Association. The State issued a Technical Interconnection and Interoperability Requirements (TIIR) document in January 2020, and issued orders requiring the utilities under PUC jurisdiction to have an approved Technical Specification Manual (TSM) published in June 2020. Municipal electric utilities are not explicitly required to have their own Technical Specification Manual, but since RPU is required to follow the same process and TIRR as the PUC regulated utilities, the municipal electric utilities have generally followed suit. RPU Engineering developed our TSM based on our unique system requirements and TSMs already published by other utilities in the state. The TSM provides a location for an entity that intends on installing a DER system in our service territory to locate the technical requirements. This document will change over time as the State of Minnesota updates the TIIR and the applicable standards for DER integration to the electric utility grid develop.

UTILITY BOARD ACTION REQUESTED:

Staff requests the Utility Board adopt the proposed Technical Specification Manual for Distributed Energy Resources effective on August 1, 2021. Staff also requests that the Utility Board grant staff the ability to make minor changes to the document to keep it current with Minnesota requirements and applicable industry standards.

TECHNICAL SPECIFICATION MANUAL (TSM)

The Technical Specifications Manual for Interconnection of Distributed Energy Resources with Rochester Public Utilities - Area Electric Power System

ROCHESTER
PUBLIC UTILITIES
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Version:

Version #	Date	Notes
1	7/1/2021	Original adopted TSM

TABLE OF CONTENTS

1. Introduction

1.1. General

The State of Minnesota has adopted technical interconnection and interoperability requirements for distributed energy resources interconnected to the distribution system. These overarching requirements are documented in what is commonly referred to as the State of Minnesota TIIR. This Technical Specification Manual, also referred to as the TSM, is an accompanying document to the TIIR. The TSM contains additional technical requirements specific to the Area EPS Operator.

Both the TIIR and the TSM are to be used with the adopted interconnection process. For municipal electric utilities in Minnesota, the interconnection process is generally known as the Municipal Minnesota DER Interconnection Process or M-MIP. Proposed DER interconnections submitted under the M-MIP relevant process adopted by the Area EPS shall be designed to comply with the technical requirements listed in the TIIR and Area EPS Operator's TSM.

The TSM is expected to be updated on a regular basis as DER technology and interconnection standards change. Interconnection Customers should confirm they are using the latest TSM version when designing their DER system. This TSM version incorporates the interim technical guidance listed in Annex C of the TIIR.

Substantial changes to existing DER systems, such as capacity additions or inverter changes, are required to be compliant with the latest version of the TIIR and TSM.

This document is not intended to describe every possible DER system interconnection or be a complete and inclusive list of all requirements. In addition to the requirements specified in this document the DER shall meet all applicable sections of the National Electric Code, National Electric Safety Code, applicable national standards (IEEE, ANSI, etc.), and the Area EPS (Rochester Public Utilities) Electric Service Rules in effect at time of initial application or major modification.

1.2. Applicability

The TSM document is designed to provide technical requirements for renewable, storage, and fossil fuel DER systems specific to the Area EPS Operator. The wide- ranging type of DER systems addressed in the TSM at times may be classified by their certification, or lack thereof, to IEEE 1547-2018. In other locations in the TSM, the DER system may be classified as how the DER system operates with the Area EPS (also known as the utility's distribution system.) The size of the DER system only will affect the types of metering, monitoring and control requirements that will be required by the Area EPS Operator.

1.3. Solar Systems Less than 40 kW

The majority of the DER interconnection applications the Area EPS Operator receives are sized less than 40 kW and are solar systems with certified inverters. While the entire TSM document applies to all DER systems, solar systems sized less than 40 kW should focus on meeting the requirements of the following sections:

- Section 4.1 – Constant Power Factor Mode
- Section 5.1 and 5.2 – Response to Abnormal Conditions
- Section 6.1, 6.2 and 6.3.6 – Protection Requirements
- Section 11 – Metering Requirements
- Section 12 – Signage and Labeling
- Section 13 – Test and Verification Requirement

These sections have been identified by a λ (lamda) at the section header. Please note these sections for application to small residential systems < 40 kW.

1.4. System Operation Type

The TSM addresses different types of DER systems by the way the DER system operates with the Area EPS. Additional information of the different types is available in the Appendix A.

1.5. Special Notations

Portions of the TSM are not currently enforced by the Area EPS Operator unless mutual agreement between the DER owner and the Area EPS Operator is reached. These sections are noted by the section title proceeded and followed by double asterisks (**). These sections will not be enforced until the Minnesota Public Utilities Commission determines certified equipment is readily available. The text under these sections will be green in color.

Sections of the TSM that are italicized are noting the text is directly from the TIIR.

1.6. Convention for Word Usage

Throughout this document, the word shall is used to indicate a mandatory requirement. The word should is used to indicate a recommendation. The word may is used to indicate a permissible action. The word can is used for statements of capability and possibility.

2. Abbreviations & Common Terms

2.1. Abbreviations

AGIR	Authority Governing Interconnection Requirements
Area EPS Operator	The utility that operates the distribution system. In this document the Area EPS Operator is Rochester Public Utilities
BPS	Bulk Power System
DER	Distributed Energy Resource
M-MIP	Municipal Minnesota DER Interconnection Process
EPS	Electric Power System
ESS	Energy Storage System
PoC	Point of Distributed Energy Resource Connection
PCC	Point of Common Coupling
RPA	Reference Point of Applicability
RTO	Regional Transmission Operator

MN DER TIIR	Minnesota Distributed Energy Resource Technical Interconnection and Interoperability Requirements
TPS	Transmission Power System
TSM	Technical Specifications Manual

2.2. Key Terms

The terms used in this document are defined in the MN DER TIIR. For quick reference, the key terms are defined in this section.

Area Electric Power System (Area EPS): The electric power distribution system connected at the Point of Common Coupling.

Area Electric Power System Operator (Area EPS Operator): An entity that owns, controls, or operates the electric power distribution system that are used for the provision of electric service.

Local Electric Power System (Local EPS): An EPS contained entirely within a single premise or group of premises.

Point of Common Coupling (PCC): The point of connection between the Area EPS and the Local EPS.

Point of Distributed Energy Resources Connection (PoC): The point where a DER unit is electrically connected in a Local EPS and meets the requirement of the MN DER TIIR and this document exclusive of any load present in the respective part of the Local EPS.

Power Control: System that controls the output (production or discharging) and input (charging) of one or more DER in order to limit output, input, export and/or import.

Reference Point of Applicability (RPA): The location where the interconnection and interoperability performance requirements specified in the MN DER TIIR and this document apply.

3. **Performance Categories**

The Area EPS Operator has no further requirements for performance categories than that provided in the MN DER TIIR at this time. Performance Category Assignment is currently not enforced unless mutual agreement between the Area EPS Operator and Interconnection Customer is reached.

3.1. **Normal – Category A and B**

The Area EPS Operator currently follows the TIIR for category assignment.

3.2. **Assignment of Abnormal Performance Category I, II or III**

The Area EPS Operator currently follows the TIIR for abnormal performance categories.

4. Reactive Power Capability and Voltage/Power Control Performance

The DER shall be capable of providing the necessary power factor to help mitigate the impact of the DER on the grid. This section provides the default and expected capabilities of a DER system on the Area EPS system.

4.1. Constant Power Factor Mode$^{\lambda}$

The voltage and reactive power control for a DER system will greatly depend on the size and location of the DER within the Area EPS. The Area EPS Operator expects that the DER system shall maintain a steady PF at the PCC. The Area EPS Operator's default settings for power factor control shall be as shown in Table 1.

Table 1 – Synchronous DER Response (shall trip) to Abnormal Voltages

DER System (kVA AC)	Power Factor	Reactive Power Control
< 40 kVA	0.98	Absorbing Reactive Power
40 kVA to < 250 kVA	0.98	Absorbing Reactive Power
250 kVA to < 5 MVA	0.98*	Absorbing Reactive Power
5 MVA to 10 MVA	0.98*	Absorbing/Providing Active Power

*Systems shall be capable of being adjusted within the range of 0.95 to 1.0 PF

During normal operation of the DER system the power factor shall never be below 0.90 at the RPA.

4.2. **Voltage and Active Power Mode**

The Area EPS Operator requires the settings for Voltage and Active Power control to be disabled.

4.3. **Voltage and Reactive Power Mode**

The Area EPS Operator requires the settings for Volt-Var control to be disabled.

5. Response to Abnormal Conditions Non-standard operations

At this time, all DER systems are required to disconnect from the Area EPS when the Area EPS experiences abnormal frequency or voltage to avoid unintentional islanding. All DER systems shall trip for any abnormal voltage or abnormal frequency with clearing times as stated in the following sections.

5.1. **Voltage Ride-Through and Tripping**$^{\lambda}$

The DER shall trip for any abnormal voltage. The Table 2 and Table 3 list the maximum clearing time for the DER system upon the occurrence of abnormal voltage levels.

Table 2 – Synchronous DER Response (shall trip) to Abnormal Voltages

Shall Trip – Synchronous DER		
Shall Trip Function	**Default Setting**	
	Clearing time (s)	**Voltage (per unit of nominal voltage)**
UV2	0.16	0.50
UV1	2.0	0.88
OV1	1.0	1.10
OV2	0.16	1.20

Table 3 – Inverter DER Response (shall trip) to Abnormal Voltages

Shall Trip – Inverter DER		
Shall Trip Function	**Default Setting**	
	Clearing time (s)	**Voltage (per unit of nominal voltage)**
UV2	0.16	0.50
UV1	2.0	0.88
OV1	1.0	1.10
OV2	0.16	1.20

No advanced voltage ride through is allowed. Future technology and situations may allow DER operations to ride-through some voltage flickers and not require the DER system to go offline, however at this time all DER systems shall be required to disconnect and reconnect for all abnormal voltage occurrences.

5.2. **Frequency Ride-Through and Tripping**$^{\lambda}$

The DER shall trip for any abnormal frequency. The following table list the maximum clearing time for the DER system upon the occurrence of abnormal frequency.

Table 4 – DER Response (shall trip) to Abnormal Frequencies

Shall Trip Function	**Default Setting**	
	Clearing time (s)	**Frequency (Hz)**
UF1	0.16	59.3
OF1	0.16	60.5

No advanced frequency ride through is allowed. Future technology and situations may allow DER operations to ride-through some frequency flickers and not require the DER system to go offline, however at this time all DER systems shall be required to disconnect and reconnect for all abnormal frequency occurrences.

6. Protection Requirements

Protective devices are required to permit safe and proper operation of the Area EPS while interconnected with DER systems. Examples of the protection requirements for different types of DER interconnections are shown in Appendix A. The figures in Appendix A are for typical installations and may not fit all possible configurations. The specific protection requirements for interconnection will depend upon the DER's size and type; the number of units; Area EPS configuration and characteristics; the operating modes of the DER; and the location of the proposed DER interconnection on the Area EPS.

An increased degree of protection is required for increased DER size. As DER capacity size increases the greater magnitude of short circuit currents and the potential impact to system stability can occur from the DER installations. Medium and large DER systems will require more sensitive and faster protection to minimize damage and ensure safety.

The interconnection of a new DER facility to the Area EPS shall not degrade any of the existing Area EPS protection and control schemes nor lower the existing levels of safety and reliability to other entities interconnected as loads to the Area EPS.

The Interconnection Customer shall provide protective devices and systems to detect the voltage, frequency and harmonic levels as defined in the IEEE 1547 during periods when the DER is operated in parallel with the Area EPS. The Interconnection Customer shall be responsible for the purchase, installation, and maintenance of these devices.

RPU primarily uses SEL protective relays and communication devices. In installations where the DER protection devices shall be able to interface with RPU's SEL protective relays, SEL's Mirrored Bits communications should used. (example: Direct Transfer Trip of DER protection devices).

6.1. Requirement of Utility AC Disconnect$^{\lambda}$

A Utility AC Disconnect furnished by the Interconnection Customer is required on all DER systems to safely isolate the DER from the Area EPS. The disconnect shall:

- Provide a visible air-gap.
- Be an AC rated device, UL or National Electrical Manufacture's Association approved.
- Be manually operable by one person.
- Be lockable in the open position.
- Be sized for adequate ampere capacity.
- Be located outside where it is continuously readily accessible, with unescorted access to the Area EPS.
- Access shall be free of obstructions from other equipment, devices, vegetation, etc.
- Does not require fasteners to be removed to access the disconnect handle.
- Be gang operated so that operation of one switch handle opens and closes all energized conductors simultaneously.
- Not interrupt neutral conductors.

The Utility AC Disconnect may be the same disconnecting means required by the NEC 690.13, 705.20 or 706.15 if the disconnect meets all the other Area EPS Operator requirements listed in this section.

6.1.1. Location of Utility AC Disconnection

The Utility AC disconnect used by the Area EPS Operator to safely isolate the DER from the Area EPS shall be located within 10 feet of the revenue meter. If the Utility AC Disconnect is proposed to not to be located within 10 feet of the revenue meter, the proposed location will be identified on the site drawing submitted to the Area EPS Operator with the Interconnection Application. The Area EPS Operator reserves the right to withhold approval for the placement of the Utility AC Disconnect in a location which is not within 10 feet of the revenue meter. If approved location is not located within 10 feet of the revenue meter, a permanently affixed placard meeting NEC requirements, as discussed in Section 12, shall be located at the revenue meter indicating the Utility AC Disconnect location. The placard shall achieve this with a mapped representation of the property, with the location of the AC disconnect denoted. An example of the placard is shown in Figure 11.

The Utility AC Disconnect shall be located between the Area EPS Operator owned equipment and the DER. For example, if a production meter is present, the disconnect shall be between the production meter and the DER. If the system voltage is greater than 240 VAC then the disconnect shall be located on the Area EPS Operator side of the production meter.

The location of the Utility AC Disconnect shall be subject to all of the height, clearance requirements, and restrictions placed on meter locations in the Area EPS most recent Electric Service Rules and Regulations.

6.2. Protection Coordination[λ]

6.2.1. Secondary Services

In general, overcurrent protection requirements shall meet the requirements of the NEC for DER interconnection that occur behind the Area EPS Operator's revenue meter. All electric services are required to have main service protection furnished by the customer immediately after the main service meter. Double-lugging meters is allowed with approved kits as long as all NEC conductor protection requirements are met.

6.2.2. Primary Services

The first protective device on the DER customer's side of the revenue meter shall coordinate with the Area EPS Operator's protective device. Protection coordination studies are required for interconnections to the primary system. The protection study shall be completed by the Interconnection Customer and reviewed and approved by the Area EPS Operator prior to interconnection and energization.

6.2.3. Coordination with Area EPS Automatic Reclosing Schemes

The Area EPS Operator may have automatic reclosing schemes designed into the Area EPS to attempt to prevent transient faults from becoming a long-term outage. The automatic reclosing scheme will de-energize a portion of the Area EPS and re-energize the same section of Area EPS in a short period of time, less than one second, often clearing the fault on the Area EPS.

Automatic reclosing on the Area EPS can potentially damage rotating DER generation, both synchronous and induction DER generators, operating in parallel with the Area EPS. The addition of DER shall not alter the standard auto restoration schemes designed in the Area EPS. The Interconnection Customer is responsible for protecting the DER facility's equipment from damage due to the automatic or manual reclosing, faults or other disturbances on the Area EPS. Contact the local EPS to identify reclosers and associated settings that may require affect operation of the DER.

6.3. Grounded Wye-Wye Protection Requirements$^{\lambda}$

The following protection requirements are for grounded wye-wye DER system interconnections. Additional protection requirements may apply for DER systems which are not grounded wye-wye or do not utilize a grounded wye-wye transformer as part of the DER interconnection system design. Non-exporting DER systems that operate in parallel with the Area EPS have the same requirements as that of any other DER interconnection.

6.3.1. General Relay Information

For DER systems which are smaller than 250 kW and utilize a certified inverter(s) for interconnection, a Professional Electrical Engineer is not required to review, test and approve the protective functions or settings of the inverter. For all other DER systems to be interconnected with Area EPS, the protective functions and relay setting shall be reviewed and approved by a Professional Electrical Engineer registered in the State of Minnesota.

Prior to energization or interconnection of the DER with the Area EPS, a copy of the proposed protective relay settings shall be supplied to the Area EPS Operator for review and approval. The Area EPS Operator shall review the protective relay settings to ensure proper coordination between the DER and the Area EPS. The proposed protective relay settings shall be provided to the Area EPS Operator with time allotted to allow for review, coordination, implementation and functional testing of the protective system including any requested modifications.

6.3.2. Non-Certified Inverters

The use of inverters that have not been tested by a Nationally Recognized Testing Laboratory (NRTL) and certified to meet the UL 1741 performance requirements are not allowed by the Area EPS Operator as an acceptable design of the DER system.

6.3.3. Relaying

All equipment providing relaying functions shall meet or exceed ANSI/IEEE Standards for protective relays, i.e., C37.90, C37.90.1 and C37.90.2.

Required relays that are not "draw-out" cased relays shall have test plugs or test switches installed to permit field testing and maintenance of the relay without unwiring or disassembling the equipment.

Three-phase interconnections shall utilize three-phase power relays, which monitor all three phases of voltage and current, unless so noted in the Appendix A diagrams.

All protective relays must have DC power supplies powered by station class batteries and charging system. The battery system shall be equipped with a DC-undervoltage detection alarm or be monitored by a continuous monitoring facility. For DER larger than 250 kW, the DC voltage level must be provided to the Area EPS Operator's SCADA system. See Section 9 for further information.

All relays shall be equipped with setting limit ranges at least as wide as specified in IEEE 1547, and meet other requirements as specified in the Area EPS interconnect study. Setting limit ranges are not to be confused with the actual relay settings required for the proper operation of the installation. At a minimum, all protective systems shall meet the requirements established in IEEE 1547.

See Appendix B for specific information regarding the types of relaying.

6.3.4. DC Power for Protection Devices

All relays and other devices which require external power to operate must be supplied by a DC battery system that can maintain power to the protective device for a minimum of 8 hours during a complete power outage. The DC battery charger shall be able to be powered by the DER if power from the Area EPS is lost. The DER shall be blocked from reconnecting to the Area EPS if the adequate DC power is not available to the protective devices.

The DC battery system shall be capable of monitoring and alarming for certain conditions related to voltage levels and charging ability. The DC battery system shall be monitored for DC voltage levels and have the capability of alarming if DC voltage reaches levels that cannot allow operation. The DC battery system shall also alarm if the battery charging system fails.

The alarms from the DC battery system shall be monitored by the Interconnection Customer. If the alarms are not monitored continuously, the alarm shall be audible or include a flashing light before complete loss of DC battery voltage.

6.3.5. Open Phase Detection

For non-inverter based DER, or inverter-based DER that opt not to use the onboard protective functions of the inverter for open-phase detection, either due to DER design configurations that render the detection method invalid or other reason, special consideration will need to be given to the methodology used to detect and trip for an open phase event.

Typical inverter-based configurations that require additional relaying include:

- Configurations with zig-zag or grounded wye-delta grounding banks.
- Configurations with delta windings on onsite transformers.

As required by IEEE 1547, all DER must detect open phase conditions at their RPA when their output is as low as 5% of their rated output, or, if not capable of producing apparent power at 5% of its rated output, at the lowest output the DER can continue producing apparent power.

The Area EPS Operator does not recommend a specific method for detecting an open phase condition, as there are many acceptable methods. Positive-sequence phase balance, zero-sequence detection and undervoltage relaying are known to be deficient protective schemes and will not be accepted for the purpose of detecting and tripping of an open phase.

- Positive-sequence phase balance and zero-sequence detection must set their pickup levels above the inherit imbalance on the Area EPS to avoid nuisance tripping. This pickup level will often be too high to allow the protective system to identify an open phase condition when the DER is at 5% output.
- Loss of phase via undervoltage relaying detection is inadequate for identifying an open phase condition. Ground banks and delta winding, present on both the DER site and on the larger Area EPS, may reconstruct voltage at the open point of the RPA.

6.3.6. Single-phase on Multiphase Services[λ]

The total nameplate rating for an individual single-phase inverter on a multi- phase system cannot exceed 10% of the distribution transformer rating that is supplying the service.

Multiple single-phase DER systems which are connecting to a multi-phase service to form a three-phase generation source, must provide protection to allow sensing and tripping of the entire DER system upon loss of a single individual phase.

DER systems which are connecting to an existing two-phase Open Delta-Wye or Open Wye-Delta secondary must be single-phase or the voltage of the service shall be converted to 120/208 or 277/480 volts.

6.4. Interconnection Transformers Connections

Interconnection Customer-owned transformers that are part of the DER system shall fall under one of the following connections.

6.4.1. Wye-Wye Transformer Connections

A Wye-Wye transformer is the preferred transformer connection. Both the primary and secondary of the transformer must be grounded. Do note, this transformer connection is subjected to harmonics from the Area EPS and the DER must be designed to limit the harmonic output from the DER system to below IEEE standard levels.

6.4.2. Wye-Delta Transformer Connections

The wye side of the transformation is required to be grounded.

High side voltage monitoring to sense single-phase faults on the primary side of the transformer is required.

All issues with zero sequence injections into the Area EPS from the Grounded Wye winding shall be addressed. Documentation is required to be provided to the Area EPS Operator for review.

6.4.3. **Delta-Wye Transformer Connections**
This transformer configuration is not allowed for interconnection of a DER system.

6.5. Grounding

For Interconnection Customer provide transformers that are part of the DER system, the transformer grounding shall properly interconnect with the grounding of the Area EPS.

6.5.1. **Requirement of Grounding Transformer**
Grounding transformers are not required by the Area EPS Operator.

6.5.2. **Wye-Wye Interconnection**
For Wye-Wye transformer configurations both the primary and secondary side of the transformer shall be grounded. The DER must also include an appropriately sized ground bank or the generator's neutral must be adequately grounded.

6.5.3. **Wye-Delta Interconnection**
For Wye-Delta transformer configurations the wye side is required to be grounded.

6.5.4. **Delta-Wye Interconnection**
Delta-Wye transformer configurations are not allowed by the Area EPS Operator for DER system interconnected to the Area EPS.

7. Operations

7.1. Periodical Testing & Record Keeping

The Interconnection Customer shall notify the Area EPS Operator prior to any of the following events occurring:

i. *Protection functions are being adjusted after the initial commissioning process.*
ii. *Functional software or firmware changes are being made on the DER.*
iii. *Any hardware component of the DER is being modified in the field or is being replaced or repaired with parts that are not substitutive components compliant with this standard.*
iv. *Protection settings are being changed after factory testing.*

Prior to modifications to the DER triggering reverification, the Interconnection Customer shall notify the Area EPS Operator's interconnection coordinator, by emailing DER@rpu.org. The email should include details about the proposed modification and the DER contact to communicate with for additional information, if needed. The Area EPS Operator strongly encourages using the DER Alteration Notification form shown in Appendix F to provide the necessary information. Any of the above events may be cause for requiring reverification of the interconnection and interoperability requirements as stated in the MN DER TIIR Section 14.5.

All interconnection-related protection and control systems shall be periodically tested and maintained, by the Interconnection Customer, at intervals specified by the manufacturer or system integrator and shall not exceed five years. Periodic test reports and a log of inspections shall be maintained by the Interconnection Customer and made available to the Area EPS Operator upon request. The Area EPS Operator shall be notified prior to the testing of the protective and control systems to witness the testing if so desired. The testing procedure for re-test should be a functional test of the protection and control systems.

The Area EPS Operator requires any system that depends upon a battery for trip/protection power shall be checked and logged once per month for proper voltage. For DER systems with nameplate rating of 1,000 kW or more, continuous monitoring of the DC battery voltage is required. Logging of all periodic inspection is recommended.

7.2. O&M Agreements

For DER systems that operate in parallel with a capacity of 40 kW or greater, the Operating and Maintenance Requirements[1] section of the Interconnection Agreement is established. The Operating and Maintenance Requirements section of the Interconnection Agreement covers items that are necessary for the reliable operation of the Local and Area EPS and are unique to each DER. The items included as Operating Requirements shall not be limited to the items shown on this list:

- *i. Operational requirements, settings, and limits for DER when the Area EPS is in a normal condition*
- *ii. Operational requirements, settings, and limits when the Area EPS is in an abnormal condition due to maintenance, contingencies, or other system issues*
- *iii. Permitted and disallowed ESS Control Modes*
- *iv. BPS or TPS limitations and arrangements that could impact DER operation*
- *v. DER restoration of output or return to service settings and limitations*
- *vi. Response to control or communication failures*
- *vii. Performance category assignments (normal and abnormal)*
- *viii. Dispatch characteristics of DER*
- *ix. Notification process between Interconnection Customer and Area EPS Operator*
- *x. Right of Access*

The following is a list of typical items that may be included as Maintenance Requirements. The items are not to be limited to the items included in this list:

- *i. Routine maintenance requirements and definition of responsibilities*
- *ii. Material modification of the DER that may impact the Area EPS*

[1]Attachment V of the Interconnection Agreement is the Operating and Maintenance Requirements for Area EPS Operator's Distribution System and Affected Systems Need to Support the Interconnection Customer's Need. This is referred to as the Operating and Maintenance Requirements in this document.

7.3. **System Voltage**

Operation of the DER shall not cause the voltage at the PCC to go outside of ANSI Range A under normal operations. Operation of the DER that causes voltages to go outside the ANSI Range A voltage values may be cause for disconnection until the reason can be identified and corrected.

For reference, ANSI C84.1-2020 defines Service Voltage as Range A. Table 5 contains Range A values for common RPU voltages:

Table 5 – Service Voltage Limits

Nominal System Voltage	Maximum Service Voltage	Minimum Service Voltage
120 (2-wire)	126	114
120/240 (3-wire)	126/252	114/228
208Y/120 (4-wire)	218Y/126	197Y/114
480Y/277	504Y/291	456Y/263
13,800Y/7,970	14,490Y/8,370	13,460Y/7,770

Any sudden voltage changes caused by the DER which adversely effect other interconnected entities to the Area EPS shall not be allowed. It is the DERs responsibility to resolve adverse voltage changes caused by the operation of their DER. The Area EPS Operator will work cooperatively with the DER to identify possible solutions.

7.4. **Power Ramp Rates**

7.4.1. **Overview**

The ability for the Area EPS to respond to large changes in increasing or decreasing demand for energy depend upon the PCC with the Area EPS. The ratio of generation to load on the Area EPS correlates with the potential of voltage disturbances on the Area EPS as generation is abruptly added or removed from extended parallel operation with the Area EPS. In some cases, if the step change is large enough, Area EPS protection devices may operate under the assumption a fault has occurred with the abrupt change in voltage. The larger the amount of load or generation added or removed from the Area EPS, the greater the chance of creating operational problems for other entities interconnected on the Area EPS.

As part of the interconnection study, the Area EPS Operator will review the potential for step changes of 3% or greater in load or energy production that can create operational problems on the Area EPS. It is the Interconnection Customer’s responsibility to review for potential Local EPS issue which may result from block changes in load or generation from the DER.

7.4.2. **Power Ramp Rates Requirements**

DER systems shall not cause the Area EPS voltage to be outside of ANSI Range A voltage levels. Block loading or off-loading of the DER generation that causes voltage step changes of 3% or greater on the Area EPS is not allowed.

7.5. Enter Service

Enter Service is the period where the DER begins operation with an energized Area EPS. Enter Service may be part of daily operation of the DER or occur after a power outage on the Area EPS. The method the DER uses to Enter Service is important to the reliability and performance of the Local EPS and the Area EPS. All DER systems shall not energize and parallel with the Area EPS unless applicable voltage and system frequency are within the ranges specified in Table 6.

Table 6 – DER Enter Service Criteria Ranges

Enter Service Criteria		Default settings
Applicable voltage within range	Minimum Value	≥ 0.917 p.u.
	Maximum Value	≤ 1.05 p.u.
Frequency within range	Minimum Value	≥ 59.3 Hz
	Maximum value	≤ 60.5 Hz

DER shall be capable of delaying enter service by an intentional adjustable minimum delay when the Area EPS steady-state voltage and frequency are within the ranges specified in Table 5. The adjustable range of the minimum intentional delay shall be 0 s to 300 s with a default minimum delay of 300 s.

7.5.1. DER without ESS

For DER that does not include ESS, possible methods which may be required include:

- The delay time for re-energization of the DER after an outage may be increased.
- The DER may be required to stagger the re-energization of inverters.
- Multiple transfer switches may be required to divide up the blocks of load transferred to the DER.

7.5.2. Energy Storage Systems

ESS shall be set to an intentional delay of a minimum of 300 s, (5 minutes), before initiating recharging of the ESS. If possible, the Area EPS Operator would prefer the ESS ramp up the recharging level from 0 – 100% over the first ten-minute time period of initial recharging. ESS larger than 250 kW may be required to have a specific intentional delay prior to enter service. The specific delay will be documented in the Operating and Maintenance Requirements section of the Interconnection Agreement.

8. Power Control Systems

8.1. General

Power Control: System that controls the output (production or discharging) and input (charging) of one or more DER in order to limit output, input, export and/or import.

Power control systems are used to control the output from a DER system due to an external condition. For example, the output from a DER unit may be limited so that it does not export energy back into the Area EPS system at the PCC. To accomplish this the power control system would sense the flow of energy at the PCC and relay that information back to the DER to limit DER output if there was any reverse energy flow at the PCC.

8.2. **Power Control System Requirements**

The power control system must be NRTL certified control system that meets the following requirements.

- Able to halt or reduce energy production within two seconds after either the period of continuous export to the Area EPS exceeds 30 seconds or the level of export exceeds the lessor of 100 kW or 10% of the DER nameplate rating.
- Able to monitor the total energy exported.
- Able to self-monitor the Power Control System, such that failure of the ability to monitor the energy flow or failure of the ability to control the output of the DER, results in halting the production of energy by the DER or the separation of the DER system from parallel operation with the Area EPS.
- The configuration and settings governing the power control limiting functions shall be password protected, accessible only by qualified personnel.
- The power to the control system must be battery backed up and if the power to the control is not available the DER system must be blocked from operation.

8.3. **Documentation**

DER applications that include a power control system must also include additional information specific to the power control system. At minimum, the following information should be supplied to the Area EPS Operator regarding the power control system.

- Make and model of the power control system.
- Electrical schematic of the monitoring for the power control system.
- User manual for the control of the power control system.
- Response time to modifying the output of the DER, in response to a large step change in the local electrical loads.
- Description of the operating reason and modes (shown in the user manual) which will be utilized.
- Description of how other operating modes (shown in the user manual) are being restricted so they are not able to be enabled.
- Other information which is useful to help the Area EPS Operator understand the power control system.

Prior to final interconnection, the Interconnection Customer shall supply updated power control system documentation to the Area EPS Operator.

8.4. **Inadvertent Export**

For installations with Power Control Systems inadvertent export is the flow of energy, in excess of a defined amount, through the PCC and back onto the Area EPS. Inadvertent export can have a detrimental effect on the Area EPS, damaging equipment or causing a power outage.

Inadvertent export shall be limited to 10% of the nameplate DER rating or 100 kW, whichever is less, for a maximum of 30 seconds. The cumulative amount of inadvertent exported energy from the Local EPS to the Area EPS, across the PCC, in any billing month shall be less than the on-site aggregated DER Nameplate Rating(s) multiplied by one hour. The power control system shall be designed to limit inadvertent export to these levels, unless mutually agreed to between the Interconnection Customer and Area EPS Operator and documented in the Operating and Maintenance Requirements section of the Interconnection Agreement.

Any amount of inadvertent export of real power across the PCC lasting longer than 30 seconds for any single event shall result in the disconnection of the DER system from the Area EPS within two seconds of exceeding the 30 second duration limit.

9. Interoperability

9.1. Overview

Depending on the method of interconnection and the size of the DER system, there are different interoperability requirements. Information from the DER is needed for the Area EPS Operator to perform fault analysis, load flow and system reliability analysis. Remote monitoring and remote control may be required depending on the size of the DER, type of interconnection and the mode of operation. In general, Table 7 displays the need for remote monitoring and remote control of the DER by size. DER with ESS that do not export may have different monitoring and control requirements. Specific remote monitoring and control requirements will be identified in the Operating and Maintenance Requirements of the Interconnection Agreement.

Table 7 – Monitoring and Control Requirements for DER Systems

Monitoring and Control Requirements for DER Systems		
DER System Nameplate Capacity	**DER Remote Monitoring**	**DER Remote Control**
0 – 250 kW	None Required	None Required
250 kW – 1,000 kW	SCADA Monitoring possible, pending review by EPS	Remote control via Area EPS Operator’s SCADA Possible, pending review by EPS
> 1,000 kW	SCADA Monitoring Required	Remote control via Area EPS Operator’s SCADA Likely, pending review by EPS

9.2. Sales to Parties Other Than the Area EPS Operator

The TSM does not address the metering, monitoring and control requirements for DER system whose energy sales are to a party other than the Area EPS Operator. For energy sales to a party other than the Area EPS Operator, the monitoring and control requirement will be identified in the Operating and Maintenance Requirements section of the Interconnection Agreement.

9.3. **Level of Communication Required**

When SCADA monitoring or SCADA monitoring and control is required, the DER Owner is responsible for the cost to provide the communications to the Area EPS Operator's control center. For DER system larger than 1,000 kW requiring monitoring and control, the Area EPS Operator will install the communication channel. The Interconnection Customer is responsible for the Area EPS Operator's cost of the communication channel and associated hardware.

The communication channel shall meet the following requirements:

- Available via a VPN tunnel,
- Able to support a polling rate of once every 2 seconds.
- Encrypted,
- Utilize DNP3.0 protocol, and
- Include a battery backup system that can last for a minimum of 8 hours during an Area EPS outage.

9.4. **Level of Monitoring and Control Required**

The actual list of status, control and analog points required to be monitored and controlled by the Area EPS Operator are to be defined in the Operating and Maintenance Requirements section of the Interconnection Agreement.

In general, the minimum points that will be required for DER systems 1,000 kW and greater are:

- Status Points
  - Lockout relay status
  - High voltage alarm
  - Low voltage alarm
  - Relay failure alarm (for each protective relay)
  - Interconnection breaker(s) status (open/close)
  - DC battery charger alarm (if applicable)
  - General trouble alarms (temperature, access, etc)
  - Control Points
  - Remote control of interconnection breaker(s) (if applicable)
  - Ability to curtail the output of the DER to a specific level (may be required in the future)
  - Ability to remotely change and/or monitor modes of operations that are active (may be required in the future)
- Analog Values
  - Phase voltage (phase to ground)
  - DER phase current (amp) output
  - Power Factor (including leading/lagging)
  - DC voltage of backup battery system
  - Three-phase real (kW) and reactive (kVA) power flow of each DER unit

Contact Area EPS Engineering Department to discuss wiring for minimum SCADA points. Other specific requirements will be included in the Interconnection Agreement.

9.5. Security

In general, all physical, network and local DER communication interface security protections should be identified by the Interconnection Customer and approved by the Area EPS Operator. Specific security requirements are listed in Sections 9.5.1, 9.5.2 and 9.5.3.

9.5.1. Physical and Front Panel

The Interconnection Customer shall maintain physical security for the DER equipment and all communication interfaces at the DER site. All configuration settings for the DER system shall be password protected to allow access only to qualified personnel. Other physical security protections shall be identified by the Interconnection Customer and approved by the Area EPS Operator.

9.5.2. Network Security

Dependent on the DER interconnection, additional network security may apply. If needed, the additional requirements will be identified in the Operating and Maintenance Requirements section of the Interconnection Agreement.

9.5.3. Local DER Communication Interface Security

Dependent on the DER interconnection, additional local DER communication interface security may apply. If needed, the additional requirements will be identified in the Operating and Maintenance Requirements section of the Interconnection Agreement.

10. Energy Storage Systems

10.1. Grid Support Functions

The TSM will not address technical issues that may arise with grid support functions. Grid support functions, such as frequency and voltage support, are currently not address by the Area EPS Operator’s rate tariff. Until MISO rules and required associated Minnesota PUC dockets have been determined, the use of an ESS to provide grid support functions is not allowed.

10.2. Common Modes of Operation

Energy storage systems are still an evolving technology with different use cases and modes of operation. Multiple control modes may be utilized by the Interconnection Customer. When applying for interconnection with the Area EPS, the DER Applicant should indicate what control modes of operation are being utilized. The Interconnection Customer must not change the control mode of the ESS without notification to the Area EPS Operator. The Area EPS Operator only studies the ESS under the indicated operation mode(s) listed on the original interconnection application. Common modes of operations used in ESS are explained in Appendix C.

10.3. **Enter Service**
After any sustained electrical outage, the ESS shall be configured to not immediately initiate recharging of the ESS. Per the IEEE 1547 standards the ESS shall wait a minimum of 5 minutes after the Area EPS is reenergized and provides a stable voltage, before initiating recharging of the ESS.

It is preferable to delay any recharging of the ESS for a minimum of 10 minutes after reenergization of the Area EPS, to allow the distribution system to fully stabilize and reduce the possibility of additional electrical demand caused by the recharging of the ESS to overload the distribution system.

To help reduce the possibility of step voltage issues and other distribution system issues, it is preferable to have the ESS control system ramp up the recharging level from 0-100% over a 5-minute time period upon entering service.

10.4. **Modification of Control Modes**
ESS Control Modes may not necessarily be considered a Material Modification, however the Interconnection Customer shall notify the Area EPS Operator of an unapproved ESS Control Mode prior to the change being implemented. The Area EPS Operator shall discuss with the Interconnection Customer the need, or lack thereof, to review the proposed ESS Control Mode for safety, power quality or reliability reasons.

The Interconnection Customer can inform the Area EPS Operator of a change in ESS control mode by emailing the Area EPS Operator's DER Coordinator a DER Alteration

Notification indicating the change in control mode. The DER Alteration Notification is shown in Appendix F. The DER Coordinator can be reached at DER@rpu.org. The ESS should not be operated in the new control mode without approval from the Area EPS Operator.

11. Metering Requirements$^{\lambda}$

The metering requirement for each DER system will depend on the DER size, voltage, location, interconnection type and application rate schedules. It is the Interconnection Customer's responsibility to provide metering sockets and cabinets for instrument transformers as applicable. All existing and new meter sockets shall meet the current requirements of the Area EPS Operators current Electric Service Rules (www.RPU.org). The Area EPS Operator will provide the meter(s), CTs and VTs, unless the DER sales are to a third party. For DER with sales to a third party, the Interconnection Customer shall be responsible for all metering costs incurred by the Area EPS Operator.

11.1. **DER Interconnection on Services with Subtractive Metering**
Subtractive Metering is ***NOT ALLOWED*** *by RPU.*

11.2. **Metering Required for DER Installation**
The metering required for DER system depends on the size and type of DER, the method of interconnection and applicable rate programs the DER may take part in. There may be unique installations which may require deviations from requirements listed in this document.

Deviations from this specification will be documented in the Operating and Maintenance Requirements section of the Interconnection Agreement.

The location and of all metering shall be subject to the requirements of applicable section of the Area EPS current Electric Service Rules and Regulations.

11.2.1. **Main Service Meter**

The main service meter, is located at the PCC, unless mutually agreed upon between the Area EPS Operator and Interconnection Customer, and is the meter the Area EPS Operator shall use for billings purposes. This is commonly called a bidirectional meter.

11.2.2. **Production Meter**

A production meter shall be required by the Area EPS Operator and is located electrically at the PoC. This meter will monitor the power flow to and from the DER. The production meter may be used for incentive programs or standby calculations and provides the Area EPS Operator with necessary information to properly engineer a safe and reliable grid. The Area EPS Operator does require a production meter for specific DER installation as listed in Section 11.3.

11.3. **Production Meter Requirement**

11.3.1. **DER Systems with ESS**

There are multiple variations of DER systems that include ESS. Depending on the configuration, non-exporting DER systems that incorporate ESS may not need a production meter. Consult with the Area EPS Operator to determine the proper metering needs.

11.3.2. **Extended Parallel DER Interconnections < 40 kW**

For extended parallel DER interconnection that are sized less than 40 kW, the Area EPS Operator requires the main meter at the PCC, and a separate production meter at the PoC. The Area EPS Operator will reprogram or replace the main service meter to be able to measure and record power flow in both directions. It is the responsibility of the Interconnection Customer to install and provide the appropriate meter sockets and cabinets for instrument transformers.

11.3.3. **Extended Parallel DER Interconnections 40 kW and Larger**

The Area EPS Operator requires the main meter at the PCC and a production meter at the PoC. The Area EPS Operator will reprogram or replace the main service meter to be able to measure and record power flow in both directions. It is the responsibility of the Interconnection Customer to install and provide the appropriate meter sockets and cabinets for instrument transformers. The Area EPS Operator will provide the meter to record production. For DER systems where the PCC and PoC are the same location a single meter can perform both types of metering.

11.3.4. **All Other DER Interconnections**

1) Contact the Area EPS for other DER interconnections that are not extended parallel.
2) See Appendix D for expected metering configurations

11.4. **Acceptable Metering**

A brief list of metering specifications is listed in the following subsections. A complete list of details and applicable references to acceptable metering voltages, metering sockets and configurations are outlined in EPS Electric Rules and Regulations (available online). Deviations from the Area EPS requirements will need to be mutually agreed to in writing by the Area EPS Operator and documented in the Operating and Maintenance Requirements section of the Interconnection Agreement. The specifications for meter socket location and accessibility shall be maintained for the life of the meter use. If changes cause the meter to no longer meet the stated specifications, the meter shall be moved to a new mutually agreed accessible location at the expense of the Interconnection Customer.

11.4.1. **Meter Sockets**

The interconnection owner is responsible for purchasing and installing a meter socket that meets the following requirements and is appropriate for the service connect.

1) Meter sockets must be UL (Underwriters Laboratories) of ARL (Applied Research Laboratories) approved.
2) All metering for a single service must be grouped in a 10-foot area.
3) All self-contained meter sockets must be a ringless lever bypass type socket with a manually operated lever bypass.
4) Must meet the requirements of the Area EPS Electric Service Rules (www.RPU.org).

11.4.2. **Location and Accessibility**

The meter socket shall be installed in a location that meets the requirements outlined in the current version of the Area EPS published Electric Service Rules (www.rpu.org)

Meter Requirements Three Phase:

See Area EPS published Electric Service Rules (www.RPU.org) and seek direction from RPUs Engineering Department by sending a request for assistance to DER@rpu.org

If at the production meter location the voltage is over 240 volts or the generators output is over 320 amps you should contact the Area EPS for assistance at DER@rpu.org.

12. Signage and Labeling$^{\lambda}$

12.1. **General Requirements**

All signage and labeling shall meet applicable NEC requirements including NEC 110.21 (B), 690.13 and 750.10.

12.2. **Utility AC Disconnect**

The Utility AC disconnect shall be labeled as “UTILITY AC DISCONNECT”. The Utility AC Disconnect shall be located within 10 feet of the main service meter in a locating meeting the requirements specified in the Area EPS Electric Service Rules (www.RPU.org). The Area EPS Operator and the Interconnection Customer may mutually agree to install the Utility AC Disconnect at a location greater than 10 feet from the main service meter.

12.2.1. **Remotely Located Utility AC Disconnect**
If the Utility AC Disconnect is not located within 10 feet of the main service meter, a permanently affixed waterproof and UV stabilized placard shall be located within 10 feet of the main service meter. The placard shall include a mapped representation of the property with the location of the Utility AC Disconnect clearly denoted. A copy of the proposed placard shall be submitted to the Area EPS Operator with the interconnection application.

12.2.2. **Multiple AC Disconnects**
If a single Utility AC Disconnect cannot be used to disconnect all DERs, all Utility AC disconnects should include numerical identification such as "UTILITY DER AC DISCONNECT 1 OF 2" or similar. The number of disconnects required to be operated to isolate the DER from the utility should be clear. A permanently affixed waterproof and UV stabilized placard shall be located within 10 feet of the main service meter clearly indicating the number and locations of the multiple Utility AC Disconnects. A copy of the proposed placard shall be submitted to the Area EPS Operator with the interconnection application.

12.3. **Production Meter**
The production meter shall be labeled as "DER PRODUCTION METER" or similar. If there are multiple DER types present at a location the production meter shall indicate the type of DER behind the meter.

13. Test and Verification Requirement$^{\lambda}$

13.1. **Applicability**
Testing and verifications of the Interconnection Customer's DER system to validate compliance with the interconnection agreement, TIIR and Area EPS Operator's TSM is critical to maintaining the safe and reliable system. The testing and verifications requirements that follow will apply to the RPA and PCC unless mutually agreed upon between the Area EPS Operator and the Interconnection Customer.

13.2. **Certified DER Systems**
It is understood that DER systems that are certified by UL 1741 / IEEE 1547 have already undergone scrutiny and testing. As such the testing required to commissioning these systems is designed to recognize the previous testing and focus on integration with the Area EPS and the final installed DER. The following testing requirements shall be met prior to parallel operation with the Area EPS:

1) Verifications of certified equipment make and model.
2) Verification of system wiring.
3) For new installations, verification of meter with Area EPS Operators metering system.
4) Verification of anti-islanding.
5) Verification of grounding.

13.3. **Non-Certified DER Systems**

For non-certified systems it is the Interconnection Customer's responsibility to provide a final design for approval and to install the protective measures required by the Area EPS Operator. Mutually agreed upon exception may at times be necessary and desirable. Prior to Commissioning of the DER the Interconnection customer shall provide the design with proof that it shall not connect or close into a de-energized Area EPS. The Interconnection Customer shall obtain written approval of the design as installed prior to completing the commissioning testing of the DER.

13.4. **Pre-Energization Testing – Interconnection Customer**

The following testing shall be performed by the Interconnection Customer. The Area EPS Operator has the right to witness all field test and review all records prior to allowing the system to be made ready for normal operation. The Area EPS Operator shall be notified with adequate lead time of witness testing in accordance to - M-MIP[2].

1) Grounding shall be verified to ensure that it complies with this specification, the NESC and the NEC.
2) CT's (Current Transformers) and VT's (Voltage Transformers) used for monitoring and protection, shall be tested to ensure correct polarity, ratio and wiring.
3) CT's shall be visually inspected to ensure that all grounding and shorting connections have been removed where required.
4) Breaker / Switch tests – Verify that the breaker or switch cannot be operated with interlocks in place or that the breaker or switch cannot be automatically operated when in manual mode. (The intent of this test is to ensure that the breaker or switch controls are operating properly).
5) Relay Tests – All protective relays shall be calibrated and tested to ensure the correct operation of the protective element. Documentation of all relay calibration tests and settings shall be furnished to the Area EPS Operator.
6) Trip checks – Protective relays shall be functionally tested to ensure the correct operation of the complete system. Functional testing requires that the complete system is operated by the injunction of currents and/or voltage to trigger the relay elements and prove that the relay element trips the required breaker, lockout or provides the correct signal to the next control element. Trip circuit shall be proven through the entire scheme (including breaker trip).
7) Remote Control, SCADA and Remote Monitoring tests – All remote-control functions and remote monitoring points shall be verified operational. For some monitoring points it may not be possible to verify analog values prior to energization. Where appropriate, those points may be verified during the energization process.
8) Phase Tests – the Interconnection Customer shall work with the Area EPS Operator to complete the phase test to ensure proper phase rotation of the DER system and wiring.

[2]*M-MIP Simplified Process section 8.3, Fast Track Process section 9.4 and Study Process section 11.3*

9) Synchronizing test – The following tests shall be done across an open switch or racked out breaker. The switch or breaker shall be in a position that it is incapable of closing between the Generation System and the Area EPS for this test. This test shall demonstrate that at the moment of the paralleling-device closure, the frequency, voltage and phase angle are within the required ranges, stated in IEEE 1547. This test shall also demonstrate that if any of the parameters are outside of the ranges stated; the paralleling device shall not close. For inverter-based interconnected systems this test may not be required unless the inverter creates fundamental voltages before the paralleling device is closed.

13.5. Energization Testing Criteria

Some tests are unable to be performed prior to interconnection with the Area EPS. Once the pre-energization tests are completed, the DER shall be integrated and the energization tests shall be performed. For larger and more complex DER systems the Interconnection Customer and Area EPS Operator should work together to develop the required testing procedure. Final proposed testing procedure shall be submitted to the Area EPS Operator prior to energization testing. The testing procedure should include the location, method of operation and verification for each step. At minimum, the testing procedure shall include the steps listed in Section 13.5.1 and 13.5.2.

13.5.1. Installation Verification

1) Prior to the anti-islanding testing, the DER system shall have the following verified:
2) That there is continuous, unescorted site access to the Area EPS equipment and Utility DER AC Disconnect is available. Site access means drivable and keyless access.
3) The DER installation matches the submitted one-line diagram that was approved by the Area EPS Operator.
4) There is proper labeling of disconnect switches, meters and placards, if necessary.
5) That the Interconnection Customer will verify the settings and firmware of the inverters, protective devices, power control systems and other hardware and software components comply with the TIIR, Area EPS Operator's TSM, operating agreements and match the previously approved settings.

13.5.2. Anti-Islanding Test

For DER systems that operate in parallel with the Area EPS, the anti-islanding test procedure shall, at minimum, contain the following steps:

1) The DER system shall be placed into normal operations.

2) The DER system shall be verified it is energized and generating.

3) The Area EPS source shall be removed from the DER system. For multi- phase systems. Each phase will be tested individually in addition to simultaneously.

4) The DER system shall be verified that it either separate from the Area EPS together with the local load or the DER system shall stop operating.

5) The DER system shall be reconnected to the Area EPS. The DER generation shall not parallel with the Area EPS for a period less than 5 minutes.

For each step, the testing procedure shall identify which device shall be operated to complete the step. In verification step, the testing procedure shall identify the point of measurement.

13.5.3. **Additional Onsite Testing**

Depending on the complexity of the DER system, additional energization tests may be required. Examples of additional tests include phase testing, control mode verification, SCADA and communication verification. These additional tests shall be listed in the Interconnection Customer's submitted testing procedure as applicable.

13.6. **Periodic Testing and Documentation**

All interconnection-related protection systems shall be periodically tested and maintained, by the Interconnection Customer, at intervals specified by the manufacturer or system integrator. These intervals shall not exceed five years. Periodic test reports and a log of inspections shall be maintained, by the Interconnection Customer and made available to the Area EPS Operator upon request. The Area EPS Operator shall be notified prior to the periodic testing of the protective systems, so that Area EPS personnel may witness the testing, if so desired.

13.6.1. **Battery Documentation**

Any system that depends upon a battery for trip/protection power shall be checked and logged once per month for proper voltage. Once every four years the battery(s) must be either replaced or a discharge test performed. Longer intervals are possible using the "station class batteries" and Area EPS Operator approval.

13.7. **Failure Protocol**

If the DER fails testing or verification, the Interconnection Customer shall address outstanding issues and provide updated documentation to the Area EPS Operator regarding the corrections made. The Interconnection Customer shall re-schedule the onsite testing with the Area EPS Operator and provide a revised testing procedure, if necessary.

13.8. **Modification to Existing DER**

Any time the interface hardware or software, including protective relaying and generation control systems are replaced and/or modified, the Area EPS Operator shall be notified. This notification shall, if possible, be with adequate notice so the Area EPS personnel can be involved in the planning for the modification and/or witness the verification testing. Verification testing shall be completed on the replaced and/or modified equipment and systems. The involvement of the Area EPS personnel will depend upon the complexity of the DER system and the component being replaced and/or modified.

14. Sample Documents for Simplified Process

14.1. Introduction

Interconnection customer shall maintain a system one-line diagram, site diagram and testing procedure with latest results.

All documentation shall include the following:

- Interconnection Customer's Name
- Interconnection Agent's Name, Address, and Phone Number
- Date and revision

14.2. One-Line Diagram

The one-line diagram shall include, but not limited to, the following information:

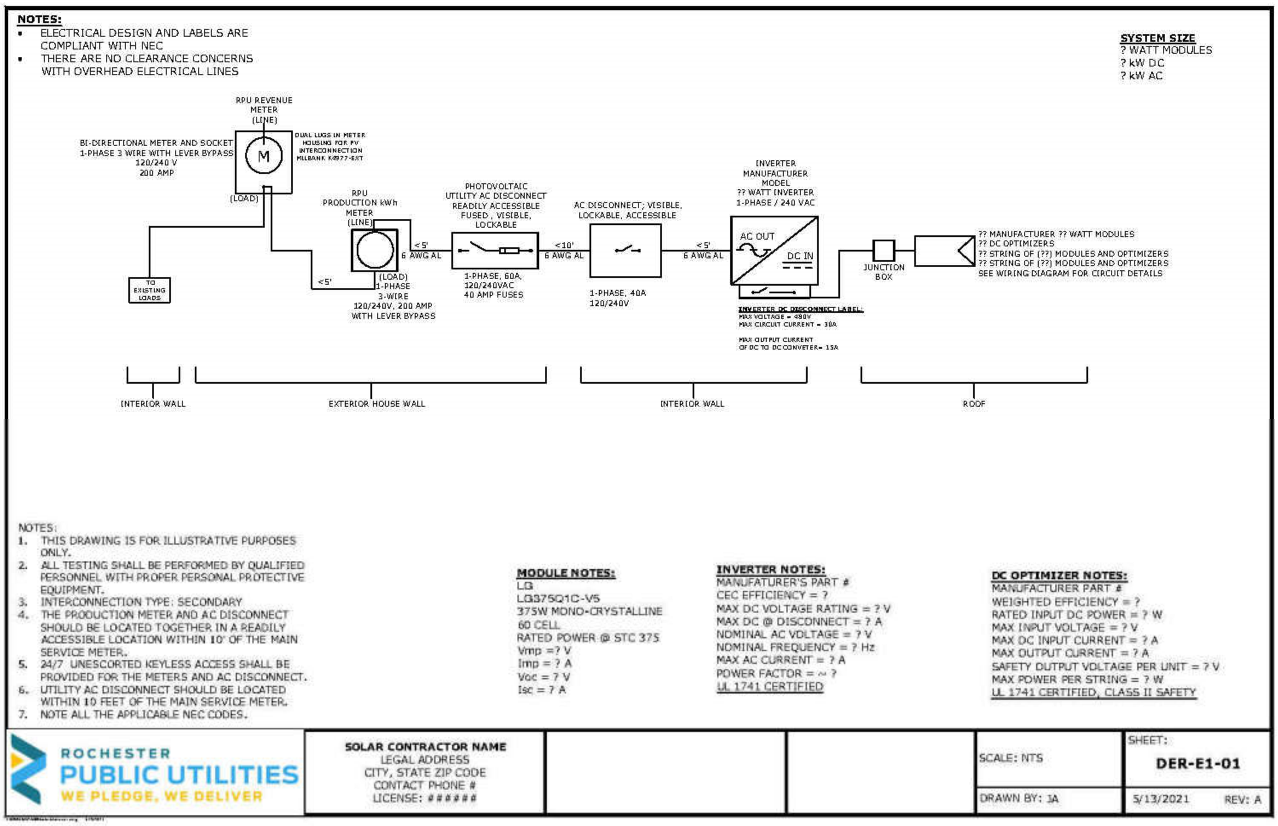
- Applicant Name
- Installer name and contact information
- Address where DER system will be installed
- Correct electrical position of all equipment, including but not limited to: Panels, Inverter, DC and AC disconnects, and metering equipment.
- Indicate the line and load side of the production and revenue meters.
- Distance between equipment
- Labeling found on equipment (actual labeling is typically on a separate drawing that shall be included with the application)
- Total Aggregated AC nameplate rating of DER
- DER protection elements

The one-line diagram shall be signed and stamped by a Minnesota Professional Engineer if the DER is larger than 20 kW and uncertified or larger than 250 kW and certified.

Key labels:

Utility AC Disconnect, DER Production Meter, Revenue Meter, Load and Line side of meter sockets, System AC and DC Rating, Customer Name and Address

Figure 14.1 Example Simplified One-Line Diagram

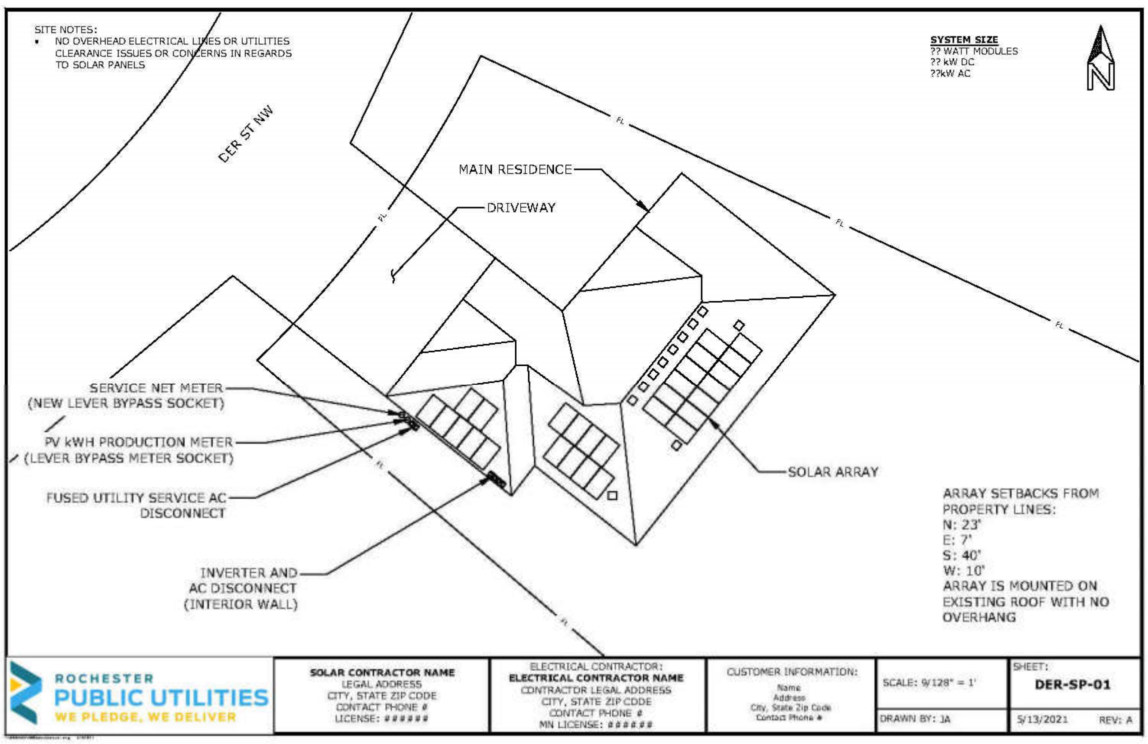


14.3. **Site Diagram**

Site Diagram shall include the following:

- Customers signature if an Application Agent is being used
- Shall be to scale
- Location of DER
- Location of meter(s)
- Location of Utility AC disconnect
- Location of PCC/RPA/PoC
- If DER installed on a different structure than the revenue meter:
- If underground, shall include any easements/right of ways

Figure 14.2 – Sample Simplified Site Diagram



14.4. **Testing Procedure**

General Process for Simplified Testing Procedures

- Verify installation matches design evaluation
  - Verify inverter model matches application
  - Verify certified inverter
  - Verify electrical inspection sticker
  - Verify correct labeling / signage
  - Verify Utility DER AC Disconnect Switch is lockable and has visual open
  - Verify DER system installation matches application one-line
  - Verification of operational and protection settings
  - Verify metering and Utility DER AC Disconnect Switch are accessible by Area EPS Operator
- Field Testing
  - On-off test
  - Open phase testing (if applicable for multiphase systems)

An example of a Simplified DER testing procedure is found in Appendix E.

Appendix A – Types of Interconnection

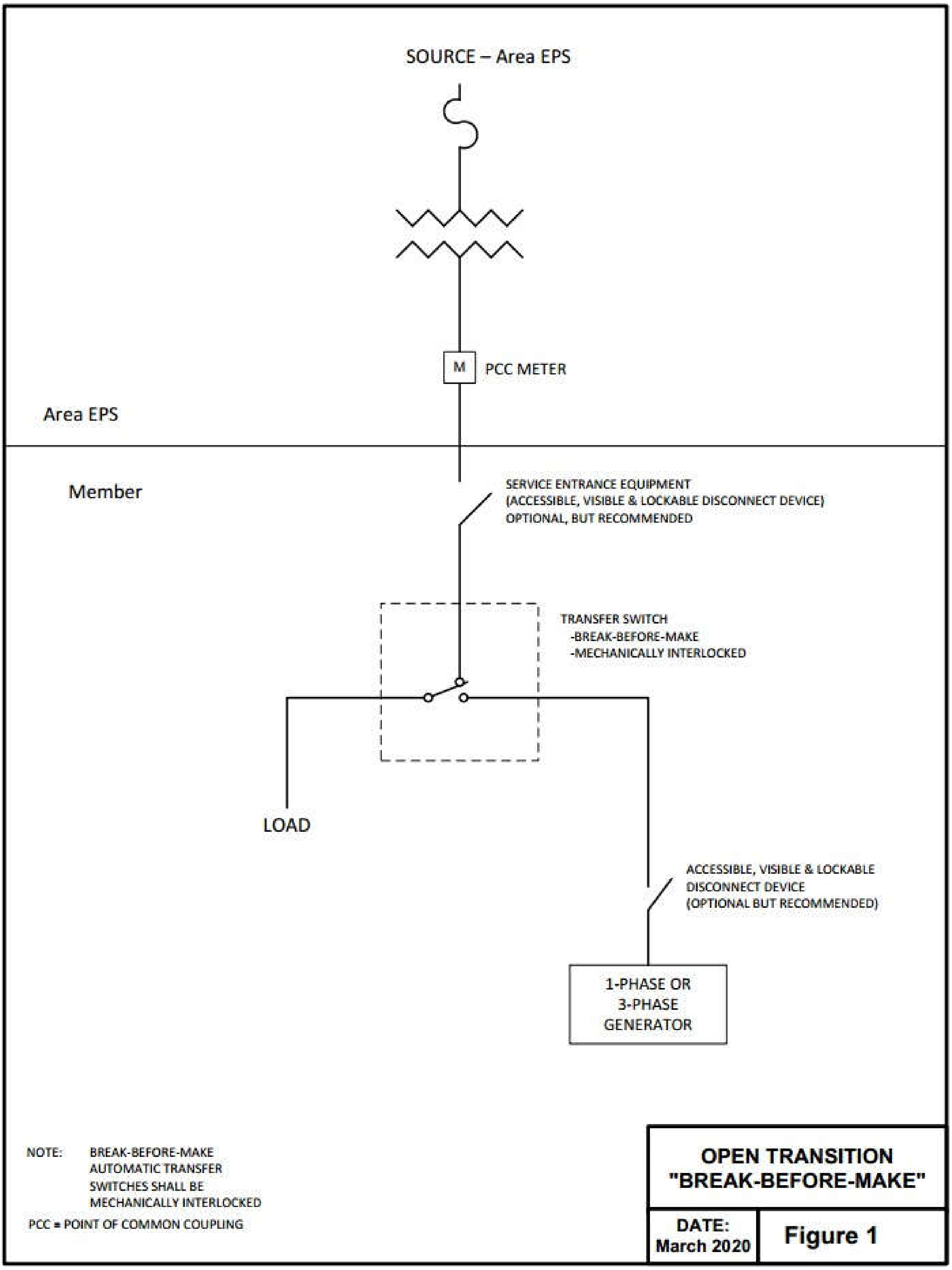
The way the DER system is connected to and disconnected from the Area EPS can vary. Most transfer systems normally operate using one of the following five methods of transferring the load from the Area EPS to the DER system.

If a transfer system is installed which has a user accessible selection of several transfer modes, the transfer mode that has the greatest protection requirements will establish the protection requirements for that transfer system.

<u>Open Transition (Break-Before-Make) Transfer Switch</u>

With this transfer switch, the load to be supplied from the DER is first disconnected from the Area EPS and then connected to the DER. This transfer can be relatively quick, but voltage and frequency excursions are to be expected during transfer. Computer equipment and other sensitive equipment will shut down and reset. The transfer switch typically consists of a standard UL approved transfer switch with mechanical interlocks between the two source contactors that drop the Area EPS source before the DER is connected to supply the load.

1) To qualify as an Open Transition switch and the limited protective requirements, mechanical interlocks are required between the two source contacts. This is required to ensure that one of the contacts is always open and the generating DER is never operated in parallel with the Area EPS. If the mechanical interlock is not present, the protection requirements are as if the switch is a closed transition switch.
2) As a practical point of application, this type of transfer switch is typically used for loads less than 500 kW. This is due to possible voltage flicker problems created on the Area EPS, when the load is removed from or returned to the Area EPS source. Depending upon the Area EPS's stiffness, this level may be larger or smaller than the 500-kW level.
3) Figure 1 on the following page provides a typical one-line of this type of installation.


SOURCE – Area EPS
M
PCC METER
Area EPS
Member
SERVICE ENTRANCE EQUIPMENT
(ACCESSIBLE, VISIBLE & LOCKABLE DISCONNECT DEVICE)
OPTIONAL, BUT RECOMMENDED
TRANSFER SWITCH
-BREAK-BEFORE-MAKE
-MECHANICALLY INTERLOCKED
LOAD
ACCESSIBLE, VISIBLE & LOCKABLE
DISCONNECT DEVICE
(OPTIONAL BUT RECOMMENDED)
1-PHASE OR
3-PHASE
GENERATOR
NOTE: BREAK-BEFORE-MAKE
AUTOMATIC TRANSFER
SWITCHES SHALL BE
MECHANICALLY INTERLOCKED
PCC = POINT OF COMMON COUPLING
OPEN TRANSITION
"BREAK-BEFORE-MAKE"
DATE:
March 2020
Figure 1

Quick Open Transition (Break-Before-Make) Transfer Switch

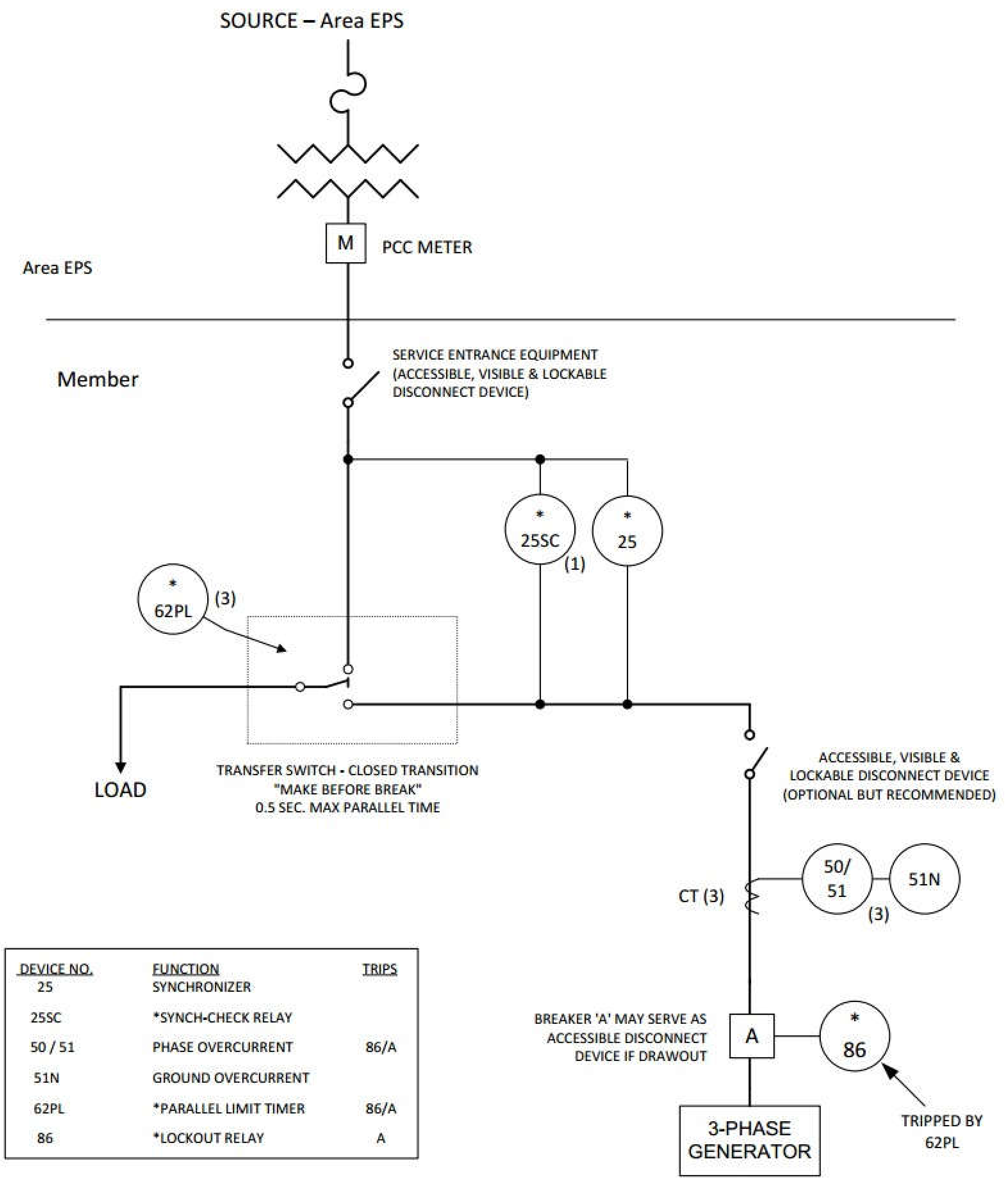
For a Quick Open Transition, the load to be supplied from the DER is first disconnected from the Area EPS and then connected to the DER, similar to the open transition. However, this transition is typically much faster (under 500 ms) than the conventional open transition transfer operation. Voltage and frequency excursions will still occur, but some computer equipment and other sensitive equipment will typically not be affected with a properly designed system. The transfer switch consists of a standard UL approved transfer switch, with mechanical interlocks between the two source contacts that drop the Area EPS source before the DER is connected to supply the load.

1) Mechanical interlocks are required between the two source contacts to ensure that one of the contacts is always open. If the mechanical interlock is not present, the protection requirements are as if the switch is a closed transition switch
2) As a practical point of application this type of transfer switch is typically used for loads less than 500 kW. This is due to possible voltage flicker problems created on the Area EPS, when the load is removed from or returned to the Area EPS source. Depending upon the Area EPS's stiffness this level may be larger or smaller than the 500-kW level.
3) Figure 1 on the previous page provides a typical one-line of this type of installation and shows the required protective elements.

Closed Transition (Make-Before-Break) Transfer Switch

For Closed Transition, the DER is synchronized with the Area EPS prior to the transfer occurring. The transfer switch then parallels with the Area EPS for a short time (500 ms or less) and then the DER and load is disconnected from the Area EPS. This transfer is less disruptive than the Quick Open Transition because it allows the DER a brief time to pick up the load before the support of the Area EPS is lost. With this type of transfer, the load is always being supplied by the Area EPS or the DER.

1) As a practical point of application this type of transfer switch is typically used for loads less than 500 kW. This is due to possible voltage flicker problems created on the Area EPS, when the load is removed from or returned to the Area EPS source. Depending upon the Area EPS's stiffness this level may be larger or smaller than the 500-kW level.
2) Figure 2 on the following page provides a typical one-line of this type of installation and shows the required protective elements. The closed transition switch must include a separate parallel time limit relay, which is not part of the generation control PLC and trips the generation from the system for a failure of the transfer switch and/or the transfer switch controls.



DEVICE NO.	FUNCTION	TRIPS
25	SYNCHRONIZER	
25SC	*SYNCH-CHECK RELAY	
50 / 51	PHASE OVERCURRENT	86/A
51N	GROUND OVERCURRENT	
62PL	*PARALLEL LIMIT TIMER	86/A
86	*LOCKOUT RELAY	A

(1) (2) (3) INDICATES NUMBER OF PHASES TO BE MONITORED

* INDICATES MINIMUM REQUIRED PROTECTION
OTHER RELAYS SHOWN ARE RECOMMENDED FOR GENERATOR PROTECTION.

PCC = POINT OF COMMON COUPLING

CLOSED TRANSITION
"MAKE-BEFORE-BREAK"

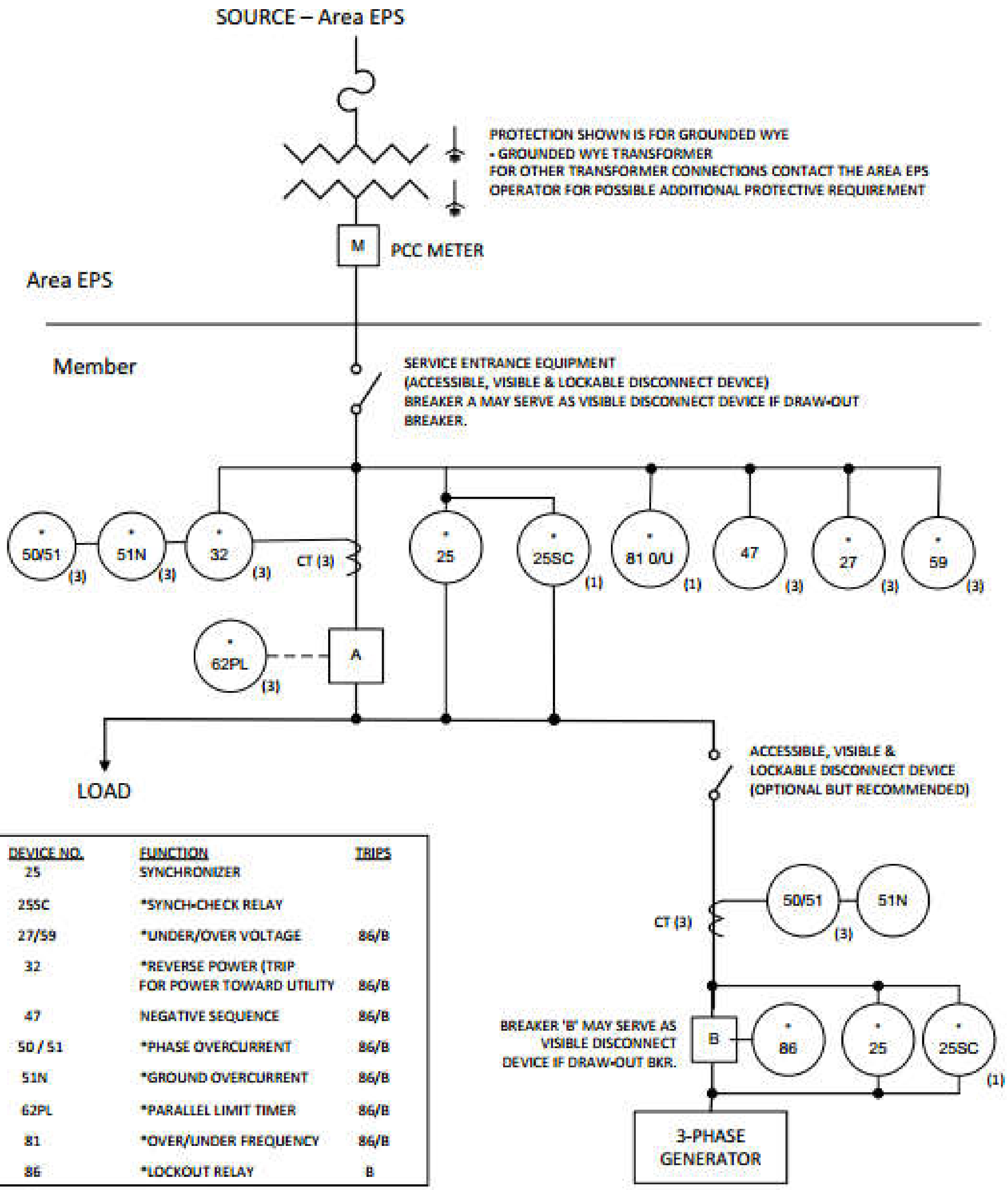
DATE:
March 2020

Figure 2

Soft Loading Transfer Switch – With Limited Parallel Operation

For this type of interconnection, the DER is paralleled with the Area EPS for a limited amount of time (generally less than 1-2 minutes) to gradually transfer the load from the Area EPS to the generating DER system. This minimizes the voltage and frequency problems, by softly loading and unloading the DER.

1) The maximum parallel operation shall be controlled, via a parallel timing limit relay (62PL). This parallel time limit relay shall be a separate relay and not part of the generation control PLC.
2) Protective Relaying is required as described in Section 6 of this document.
3) Figure 3 on the following page provide typical one-line diagrams of this type of installation and show the required protective elements.



DEVICE NO.	FUNCTION	TRIPS
25	SYNCHRONIZER	
25SC	*SYNCH-CHECK RELAY	
27/59	*UNDER/OVER VOLTAGE	86/B
32	*REVERSE POWER (TRIP FOR POWER TOWARD UTILITY	86/B
47	NEGATIVE SEQUENCE	86/B
50 / 51	*PHASE OVERCURRENT	86/B
51N	*GROUND OVERCURRENT	86/B
62PL	*PARALLEL LIMIT TIMER	86/B
81	*OVER/UNDER FREQUENCY	86/B
86	*LOCKOUT RELAY	B

(1) (2) (3) INDICATES NUMBER OF PHASES MONITORED

*INDICATES MINIMUM REQUIRED PROTECTION.

OTHER RELAYS SHOWN ARE RECOMMENDED FOR GENERATOR PROTECTION.

PCC = POINT OF COMMON COUPLING

SOFT LOADING TRANSFER LIMITED PARALLEL OPERATION

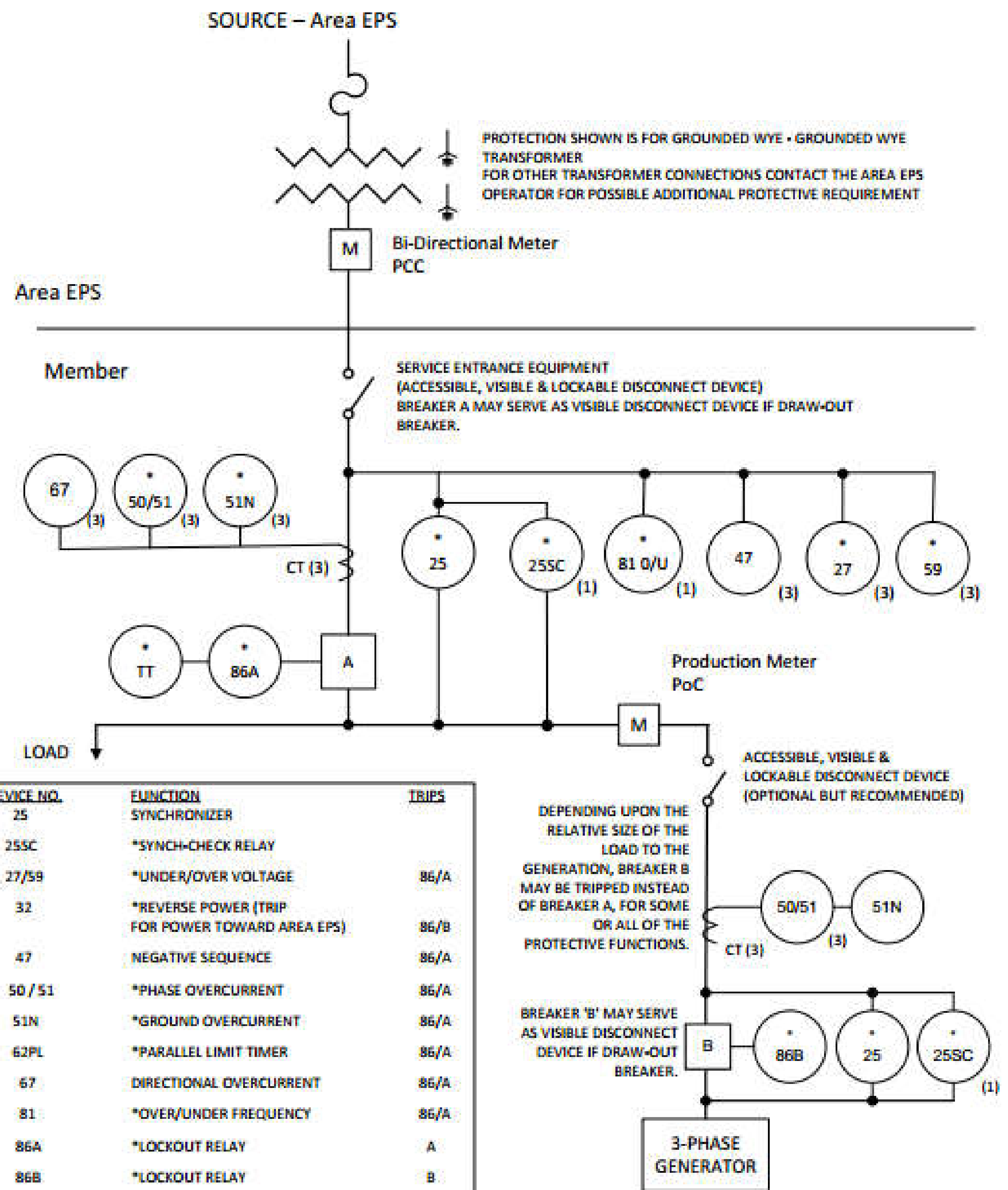
DATE: March 2020

Figure 3

Soft Loading Transfer Switch – With Extended Parallel Operation

The DER is paralleled with the Area EPS in continuous operation. Special design, coordination and agreements are required before any extended parallel operation will be permitted. The Area EPS interconnection study will identify the issues involved.

1) Any anticipated use in the extended parallel mode requires special agreements and special protection coordination.
2) Protective Relaying is required as described in Section 6 of this document.
3) Figure 4 on the following page provides a typical one-line for this type of interconnection. It must be emphasized that this is a typical installation only and final installations may vary from the examples shown due to transformer connections, breaker configuration, etc.



DEVICE NO.	FUNCTION	TRIPS
25	SYNCHRONIZER	
25SC	*SYNCH-CHECK RELAY	
27/59	*UNDER/OVER VOLTAGE	86/A
32	*REVERSE POWER (TRIP FOR POWER TOWARD AREA EPS)	86/B
47	NEGATIVE SEQUENCE	86/A
50 / 51	*PHASE OVERCURRENT	86/A
51N	*GROUND OVERCURRENT	86/A
62PL	*PARALLEL LIMIT TIMER	86/A
67	DIRECTIONAL OVERCURRENT	86/A
81	*OVER/UNDER FREQUENCY	86/A
86A	*LOCKOUT RELAY	A
86B	*LOCKOUT RELAY	B
TT	*TRANSFER TRIP	86/A

TT IS NOT REQUIRED FOR GENERATION SYSTEMS SMALLER THEN 250KW

(1) (2) (3) INDICATES NUMBER OF PHASES MONITORED

*INDICATES MINIMUM REQUIRED PROTECTION.

OTHER RELAYS SHOWN ARE RECOMMENDED FOR GENERATOR PROTECTION.

PCC = POINT OF COMMON COUPLING

SOFT LOADING EXTENDED PARALLEL OPERATION

DATE: March 2020	**Figure 4**

<u>**Inverter Connection**</u>

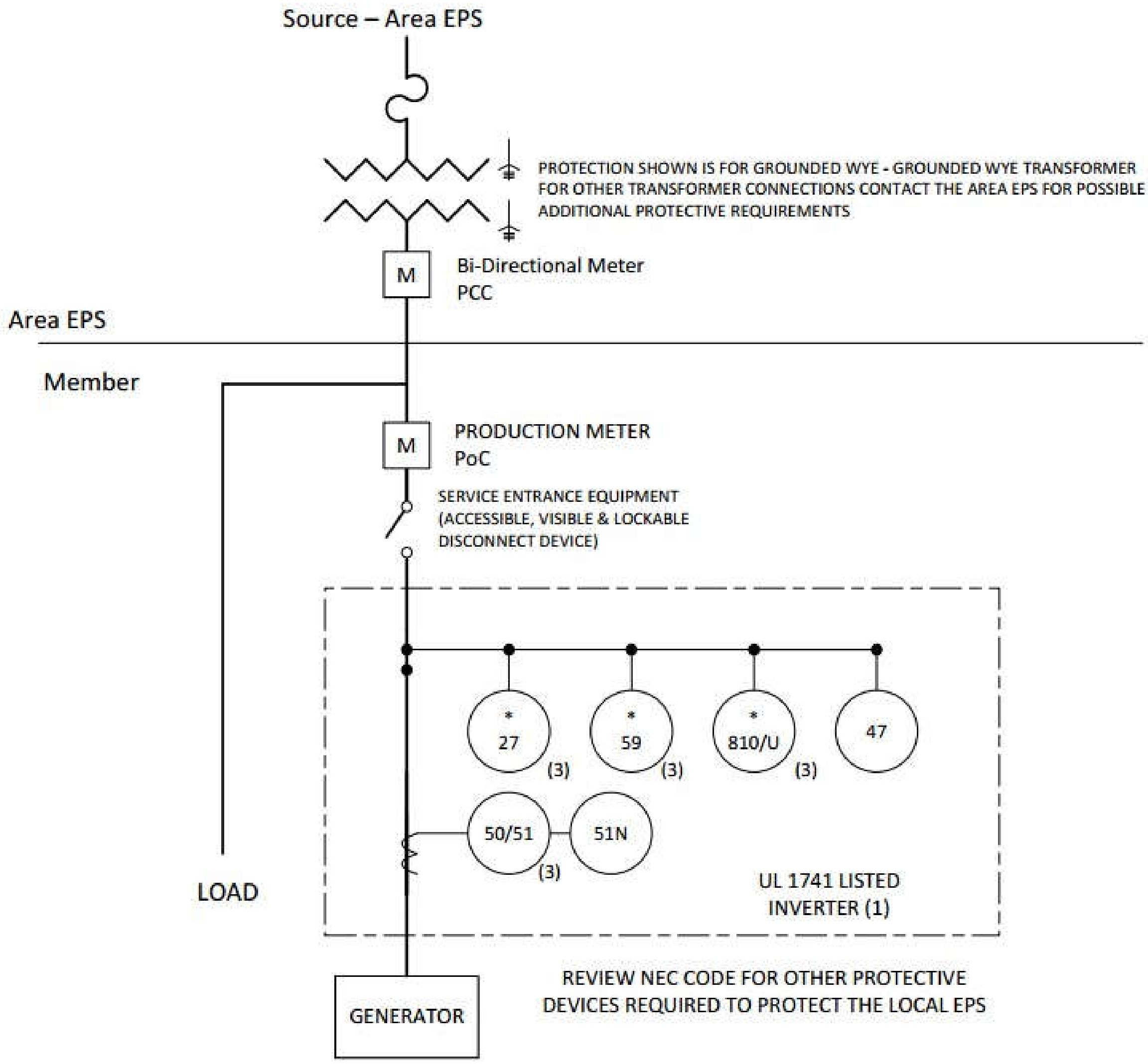
An inverter Connection is a continuous parallel connection between the DER and Area EPS. Small generating DER systems may utilize inverters to interface to the Area EPS. Solar, wind and fuel cells are some examples of DER which typically use inverters to connect to the Area EPS. The design of such inverters shall either contain all necessary protection to prevent unintentional islanding, or the Interconnection Customer shall install conventional protection to affect the same protection. All required protective elements for a soft-loading transfer switch apply to an inverter connection. Figure 5 on the following page shows a typical inverter interconnection.

1) <u>Inverter Certification</u> – Prior to installation, the inverter shall be Type-Certified for interconnection to the electrical power system. The certification will confirm its anti- islanding protection and power quality related levels at the Point of Common Coupling. Also, utility compatibility, electric shock hazard and fire safety are approved through UL listing of the model. Once this Type Certification is completed for that specific model, additional design review of the inverter should not be necessary by the Area EPS Operator.

2) For three-phase operation, the inverter control must also be able to detect and separate for the loss of one phase. Larger inverters will still require custom protection settings, which must be calculated and designed to be compatible with the specific Area EPS being interconnected with.

3) A visible disconnect is required for safely isolating the DER when connecting with an inverter. The inverter shall not be used as a safety isolation device.

4) When banks of inverter systems are installed at one location, a design review by the Area EPS Operator must be performed to determine any additional protection systems, metering or other needs. The issues will be identified by the Area EPS Operator during the interconnection process.



NOTE (1): GRID SUPPORTING or SMART Inverters meeting UL-1741 SA requirements are preferred.

DEVICE NO.	FUNCTION
27/59	*UNDER/OVER VOLTAGE
47	NEGATIVE SEQUENCE
50 / 51	PHASE OVERCURRENT
51N	GROUND OVERCURRENT
81O/U	*OVER/UNDER FREQUENCY

(1) (2) (3) INDICATES NUMBER OF PHASES MONITORED

*INDICATES MINIMUM REQUIRED PROTECTION.

OTHER RELAYS SHOWN ARE RECOMMENDED FOR GENERATION PROTECTION

PCC = POINT OF COMMON COUPLING

ECP = DER ELECTRICAL CONNECTION POINT

INVERTER CONNECTED	
DATE: March 2020	Figure 5

Appendix B – Relay Functions

Non-Certified installation, depending on the interconnection configuration, are required to provide the appropriate relay function listed in this section. The interconnection types in Appendix A will specify which relay function may be applicable.

Over-current relay (IEEE Device 50/51 or 50/51V) shall operate to trip the protecting breaker at a level to ensure protection of the equipment and at a speed to allow proper coordination with other protective devices. For example, the over-current relay monitoring the interconnection breaker shall operate fast enough for a fault on the customer's equipment, so that no protective devices will operate on the Area EPS. 51V is a voltage restrained or controlled over- current relay and may be required to provide proper coordination with the Area EPS.

Directional Over-Current Relay (IEEE Device 67) This element uses the phase relationship of the voltage and current to determine direction of the fault.

Over-Voltage Relay (IEEE Device 59) shall operate to trip the DER per the requirements of IEEE 1547. See table in Section 5.1.

Under-Voltage Relay (IEEE Device 27) shall operate to trip the DER per the requirements of IEEE 1547. See table in Section 5.1.

Over-Frequency Relay (IEEE Device 81O) shall operate to trip the DER off-line per the requirements of IEEE 1547. See table in Section 5.2.

Under-Frequency Relay (IEEE Device 81U) shall operate to trip the DER off-line per the requirements of IEEE 1547. See table in Section 5.2.

Synch Check Relay (IEEE Device 25 / 25SC) The Area EPS will provide the reference frequency of 60 Hz. The DER control system must be used to match this reference. The protective relaying in the interconnection system will be expected to maintain the frequency of the output of the DER.

Phase Sequence or Phase Balance Detection (IEEE Device 47) Provides protection for rotating equipment from the damaging effects of excessive negative sequence voltage resulting from a phase failure, phase unbalance and reversed phase sequence. This element helps the DER sense loss of source issues on the Area EPS.

Reverse Power Relays (IEEE Device 32) (power flowing from the DER to the Area EPS) shall operate to trip the DER off-line for a power flow to the system with a maximum time delay of2.0 seconds.

Lockout Relay (IEEE Device 86) is a mechanically locking device which is wired into the close circuit of a breaker or switch and when tripped will prevent any close signal from closing that device. This relay requires that a person manually resets the lockout relay before that device can be reclosed. These relays are used to ensure that a de-energized system is not reenergized by automatic control action and prevents a failed control from auto-reclosing an open breaker or switch.

Transfer Trip – All DERs are required to disconnect from the Area EPS when the Area EPS is disconnected from its source, to avoid unintentional islanding. A transfer trip system may be required to sense the loss of the Area EPS source for larger DERs which remain in parallel with the Area EPS.

When the Area EPS source is lost, a signal is sent to the DER to separate the DER from the Area EPS. The size and type of the DER and the capacity and minimum loading on the Area EPS circuit will dictate the need for transfer trip installation. The Area EPS interconnection process will identify the specific requirements for the proposed DER system.

If multiple Area EPS sources are available, or multiple points of sectionalizing exist on the Area EPS, more than one transfer trip system may be required. The Area EPS interconnection process will identify the specific requirements for the proposed DER system in this situation. For some installations, the alternate Area EPS source(s) may not be utilized except in rare occasions. In this situation, the Interconnection Customer may elect to have the DER locked out when the alternate source(s) are utilized, if agreeable to the Area EPS Operator.

Parallel Limit Timing Relay (IEEE Device 62PL) set at a maximum of 120 seconds for soft transfer installations and set no longer than 500 ms for closed transfer installations, shall trip the DER circuit breaker on limited parallel interconnection systems. Power for the 62 PL relay must be independent of the transfer switch control power.

Minimum Input Relay (IEEE Device 37) is a setting within a digital relay that will trip the DER if the level of energy flow from the Area EPS goes below a set value. This protection system may be used by the DER to detect faults on the Area EPS. Minimum input relaying schemes must be set to trip immediately upon sensing under power levels and must coordinate with the Area EPS. Minimum input relaying is not allowed for DER systems which have the potential for inadvertent energy flow onto the Area EPS.

The Area EPS primarily uses SEL protective relays for distribution system protection. If DER protection devices are required to interface with RPU's SEL protective relays, SEL's Mirrored Bits communications protocol should be the communication scheme.

Table 7 – Summary of Relaying Requirements

Summary of Relaying Requirements								
Type of Interconnection	**Over Current (50/51)**	**Voltage (27/59)**	**Frequency (81 O/U)**	**Reverse Power (32)**	**Lockout (86)**	**Parallel Limit Timer (62)**	**Synch Check (25)**	**Transf Trip**
Certified Inverter Connected < 250 kW	(1)	(1)	(1)	--	--	--	(1)	--
Certified Inverter Connected > 250 kW	Yes (2)	Yes (2)	Yes (2)	Yes (2)	Yes (2)	Yes (2)	Yes (2)	Yes (3
Limited Parallel Quick Open Transition Mechanically Interlocked	--	--	--	--	Yes	Yes	Yes	--
Limited Parallel Closed Transition	--	--	--	--	Yes	Yes	Yes	--
Soft Loading Limited Parallel Operations	Yes	Yes	Yes	Yes	Yes	Yes	Yes	--
Soft Loaded Extended Parallel < 250 kW	Yes	Yes	Yes	--	Yes	--	Yes	--
Soft Loaded Extended Parallel > 250 kW	Yes	Yes	Yes	--	Yes	--	Yes	Yes (3
Extended Parallel > 250 kW	Yes	Yes	Yes	Yes	Yes	--	Yes	Yes (3

Note (1): Function is part of a certified inverter.

Note (2): For inverter-based DER that is 250 kW or larger, a breaker and relaying is required for interconnection with the Area EPS.

Note (3): Direct Transfer-Trip is required if the Area EPS determines the proposed DER cannot detect and trip for an Area EPS fault or loss of source supply to the Area EPS within an acceptable time-frame.

Appendix C – Types of ESS Control Modes

Common types of ESS control modes are listed in this section. Not all possible control modes are identified and many ESS vendors have different names for similar control modes. For clarity between the Area EPS Operator and the Interconnection Customer, it is helpful to identify which control modes the ESS is capable of and is using on the Storage Application using one of the control modes terms below.

Emergency Power

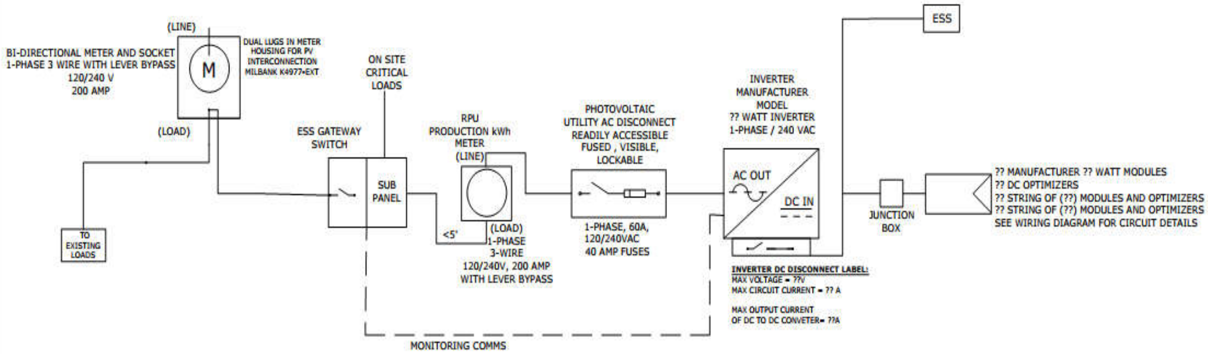
The emergency power control mode has the ESS only providing energy to the Local EPS during a power outage and not providing energy to the Local EPS in any other situation. This control mode would have the ESS remaining in a charged state until Area EPS was de-energized. Once the Area EPS was not the source of the local EPS, a switch opens isolating the backed-up load from of the Area EPS and the ESS would release energy. Upon reenergization of the Area EPS the switch closes the load so it is sourced from the Area EPS. The ESS would cease in all operation for ten minutes prior to moving to a state of charging. (See Section 10.3 Enter Service).

Figure 6. Example of Typical One-line Diagram for Emergency Power Control Mode

NOTES:
- ELECTRICAL DESIGN AND LABELS ARE COMPLIANT WITH NEC
- THERE ARE NO CLEARANCE CONCERNS WITH OVERHEAD ELECTRICAL LINES

ELECTRIC ONE-LINE DIAGRAM EMERGENCY POWER

SYSTEM SIZE
? WATT MODULES
? kW DC
? kW AC



NOTES:
1. THIS DRAWING IS FOR ILLUSTRATIVE PURPOSES ONLY.
2. ALL TESTING SHALL BE PERFORMED BY QUALIFIED PERSONNEL WITH PROPER PERSONAL PROTECTIVE EQUIPMENT.
3. INTERCONNECTION TYPE: SECONDARY
4. THE PRODUCTION METER AND AC DISCONNECT SHOULD BE LOCATED TOGETHER IN A READILY ACCESSIBLE LOCATION WITHIN 10' OF THE MAIN SERVICE METER.
5. 24/7 UNESCORTED KEYLESS ACCESS SHALL BE PROVIDED FOR THE METERS AND AC DISCONNECT.
6. UTILITY AC DISCONNECT SHOULD BE LOCATED WITHIN 10 FEET OF THE MAIN SERVICE METER.
7. NOTE ALL THE APPLICABLE NEC CODES.

MODULE NOTES:
LG
LG375Q1C-V5
375W MONO-CRYSTALLINE
60 CELL
RATED POWER @ STC 375
Vmp =? V
Imp = ? A
Voc = ? V
Isc = ? A

INVERTER NOTES:
MANUFATURER'S PART #
CEC EFFICIENCY = ?
MAX DC VOLTAGE RATING = ? V
MAX DC @ DISCONNECT = ? A
NOMINAL AC VOLTAGE = ? V
NOMINAL FREQUENCY = ? Hz
MAX AC CURRENT = ? A
POWER FACTOR = ~ ?
UL 1741 CERTIFIED

DC OPTIMIZER NOTES:
MANUFACTURER PART #
WEIGHTED EFFICIENCY = ?
RATED INPUT DC POWER = ? W
MAX INPUT VOLTAGE = ? V
MAX DC INPUT CURRENT = ? A
MAX OUTPUT CURRENT = ? A
SAFETY OUTPUT VOLTAGE PER UNIT = ? V
MAX POWER PER STRING = ? W
UL 1741 CERTIFIED, CLASS II SAFETY

ROCHESTER PUBLIC UTILITIES WE PLEDGE, WE DELIVER	SOLAR CONTRACTOR NAME LEGAL ADDRESS CITY, STATE ZIP CODE CONTACT PHONE # LICENSE: ######			SCALE: NTS DRAWN BY: JA	SHEET: DER-E1-04 5/18/2021 REV: A

Demand Reduction Management

The demand reduction management operating mode has the ESS releasing stored power to reduce the peak demand of the Local EPS. This control mode would have the ESS providing energy to the Local EPS while the Local EPS is also receiving energy from the Area EPS. The ESS would incorporate an energy management system that monitors the load of the Local EPS. When the Local EPS reaches a set demand point, the ESS would release stored power in specified amount. The result is the demand required from the Area EPS would stay at a levelized amount. This type of control mode can be used with electrical services that are billed retail with a volumetric energy component and a demand component. The example one-line of this type of control mode is shown in Figure 7.

Non-Exporting, Self-Consumption

The non-exporting or self-consumption mode incorporates a generating DER, such as a solar system, that would charge the ESS. As the generation exceeds the load, the ESS is charged. When the load exceeds the generation, the ESS can release energy to maintain the power needs of the load is covered, but neither the ESS nor the generating DER (solar) will send power to the Area EPS. This control mode normally includes information from an energy management system. The example one-line of this type of control mode is shown in Figure 7.

Time-Of-Use Management

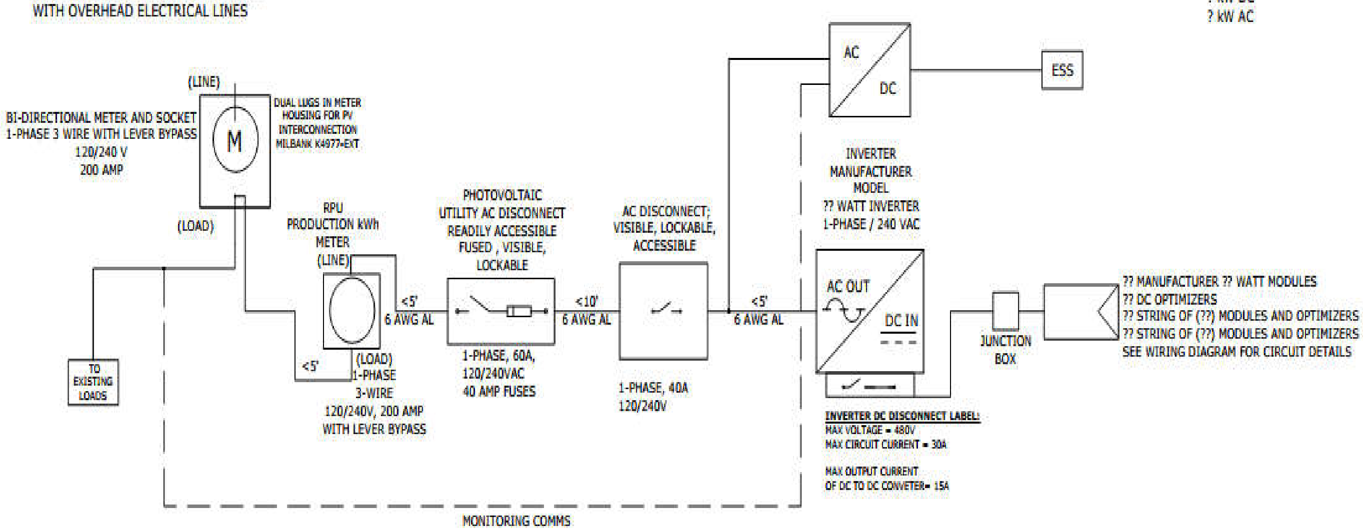
The time-of-use management control mode has the ESS charging when retail energy prices are low and releasing energy when energy prices are high, offsetting the need for the load to use energy from the Area EPS. This control mode is only beneficial to the interconnection customer if the electric service is on a retail time-of-use rate schedule. The example one-line of this type of control mode is shown in Figure 7.

Figure 7. Example of Typical One-line Diagram for Load Modify Control Mode

NOTES:
- ELECTRICAL DESIGN AND LABELS ARE COMPLIANT WITH NEC
- THERE ARE NO CLEARANCE CONCERNS WITH OVERHEAD ELECTRICAL LINES

ELECTRIC ONE-LINE DIAGRAM LOAD MODIFYING

SYSTEM SIZE
? WATT MODULES
? kW DC
? kW AC



NOTES:
1. THIS DRAWING IS FOR ILLUSTRATIVE PURPOSES ONLY.
2. ALL TESTING SHALL BE PERFORMED BY QUALIFIED PERSONNEL WITH PROPER PERSONAL PROTECTIVE EQUIPMENT.
3. INTERCONNECTION TYPE: SECONDARY
4. THE PRODUCTION METER AND AC DISCONNECT SHOULD BE LOCATED TOGETHER IN A READILY ACCESSIBLE LOCATION WITHIN 10' OF THE MAIN SERVICE METER.
5. 24/7 UNESCORTED KEYLESS ACCESS SHALL BE PROVIDED FOR THE METERS AND AC DISCONNECT.
6. UTILITY AC DISCONNECT SHOULD BE LOCATED WITHIN 10 FEET OF THE MAIN SERVICE METER.
7. NOTE ALL THE APPLICABLE NEC CODES.

MODULE NOTES:
LG
LG375Q1C-V5
375W MONO-CRYSTALLINE
60 CELL
RATED POWER @ STC 375
Vmp =? V
Imp = ? A
Voc = ? V
Isc = ? A

INVERTER NOTES:
MANUFATURER'S PART #
CEC EFFICIENCY = ?
MAX DC VOLTAGE RATING = ? V
MAX DC @ DISCONNECT = ? A
NOMINAL AC VOLTAGE = ? V
NOMINAL FREQUENCY = ? Hz
MAX AC CURRENT = ? A
POWER FACTOR = ~ ?
UL 1741 CERTIFIED

DC OPTIMIZER NOTES:
MANUFACTURER PART #
WEIGHTED EFFICIENCY = ?
RATED INPUT DC POWER = ? W
MAX INPUT VOLTAGE = ? V
MAX DC INPUT CURRENT = ? A
MAX OUTPUT CURRENT = ? A
SAFETY OUTPUT VOLTAGE PER UNIT = ? V
MAX POWER PER STRING = ? W
UL 1741 CERTIFIED, CLASS II SAFETY

ROCHESTER PUBLIC UTILITIES WE PLEDGE, WE DELIVER	SOLAR CONTRACTOR NAME LEGAL ADDRESS CITY, STATE ZIP CODE CONTACT PHONE # LICENSE: ######			SCALE: NTS DRAWN BY: JA	SHEET: DER-E1-03 5/13/2021 REV: A

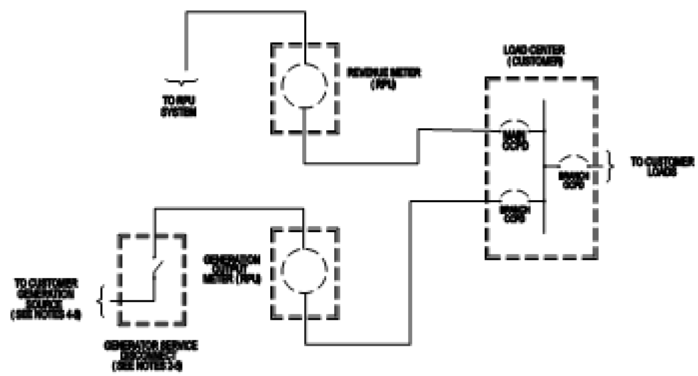
Appendix D – Simplified Diagrams for Various Rate Options

These one-line diagrams are simplified and do not include all relevant equipment. They are intended to depict metering configurations for the various options for qualifying facilities that are 100 kW or less in size.

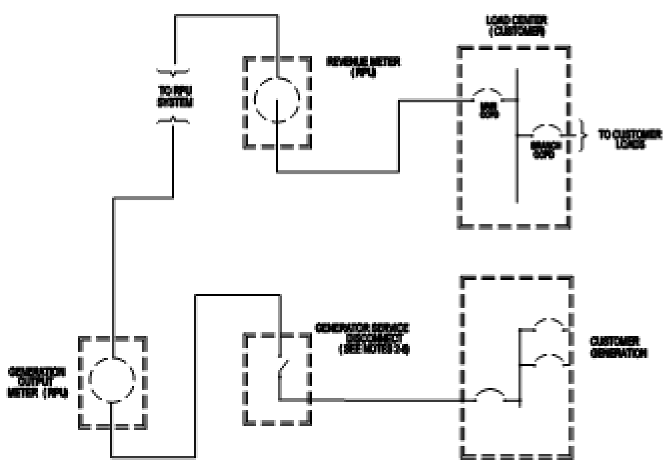
Figure 8.(Drawing ME1I01) Qualifying Facility Average Retail Rate, Roll-over Credit, Time of Day, and Simultaneous Purchase and Sale Configurations

Figure 8. Qualifying Facility less than 100 kW; Average Retail Rate, Roll-over Credit, Time of Day, and Simultaneous Purchase and Sale Configurations

Average Retail Rate (<=40 KW), Roll-over Credit (<=40 KW), & Time of Day Configuration (<=100 KW)



Simultaneous Purchase and Sale Configuration



1. Both the revenue meter socket and the generation output meter socket shall be lever bypass style for self contained meters.
2. Disconnect and generation meter must be installed outside within 10 feet of revenue meter and readily accessible
   (Contact RPU to discuss options of disconnect cannot be within 10ft of the revenue meter)
3. Disconnect must be clearley marked "GENERATOR DISCONNECT SWITCH"
4. Disconnect must allow for lockout / tagout capability
5. Disconnect must open all phases
6. Customer generation must be capable of synchronizing with service voltage phase and magnitude
7. Meter socket supplied by customer

NOT TO SCALE

ROCHESTER PUBLIC UTILITIES

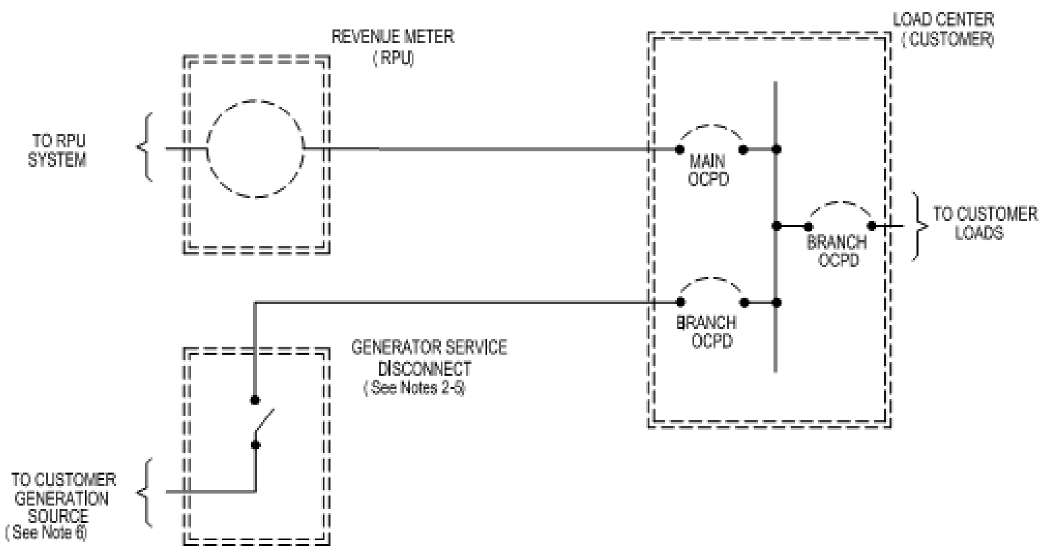
NO	REVISION	APPROVED BY	DATE
0	ORIGINAL DRAWING	SJC	5/11
1	ADDED GENERATION OUTPUT METER	SJC	7/27/11
2	ADDED NOTE #7	JSA	3/8/18
3	ADDED OPTION FOR 10% Rule	SJC	7/29/19
4	ADDED LEVER BYPASS	SJC	9/29/20
5	ADDED MAX GENERATION NOTES & RECONFIGURED DRAWING TO DEPICT LOAD/LINE	SJC	6/8/21

QUALIFYING GENERATION INTERCONNECT LESS THAN 100 KW

DWG # ME1MI01

ISSUE DATE – MAY 11

Figure 9. Non Qualifying Generation Interconnect Less than 40 KW



1. Meter socket shall be a lever bypass style for self contained meters and supplied and installed by customer.
2. Disconnect must be installed outside within 10 feet of revenue meter and readily accessable
3. Disconnect must be clearley marked "GENERATOR DISCONNECT SWITCH"
4. Disconnect must allow for lockout/tagout (lockable) capability
5. Disconnect must open all phases and neutral
6. Customer generation must be capable of synchronizing with service voltage phase and magnitude

NOT TO SCALE

ROCHESTER PUBLIC UTILITIES

NO	REVISION	APPROVED BY	DATE
0	ORIGINAL DRAWING	SJC	5/11
1	ADDED BYPASS SOCKET NOTE	SJC	11/25/19

NON QUALIFYLING GENERATION INTERCONNECT LESS THAN 40 KW

DWG # ME1M02

ISSUE DATE – MAY 11

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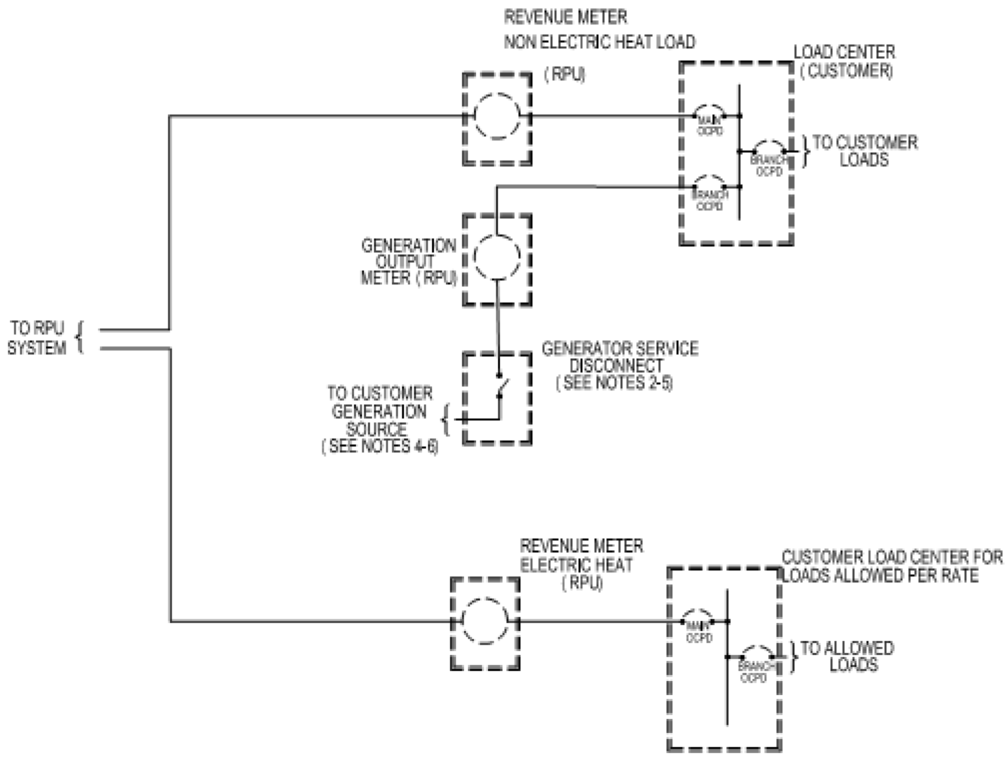
Figure 10. Qualifying Generation with Dual Fuel or Roll Over Credit

Dual Fuel with Average Retail Rate or Roll Over Credit (Typical)



1. Both the revenue meter socket and the generation output meter socket shall be lever bypass style for self contained meters.
2. Disconnect and generation meter must be installed outside within 10 feet of revenue meter and readily accessible
   (Contact RPU to discuss options of disconnect cannot be within 10ft of the revenue meter)
3. Disconnect must be clearley marked "GENERATOR DISCONNECT SWITCH"
4. Disconnect must allow for lockout / tagout (lockable) capability
5. Disconnect must open all phases
6. Customer generation must be capable of synchronizing with service voltage phase and magnitude
7. Meter socket supplied by customer

NOT TO SCALE

ROCHESTER PUBLIC UTILITIES

NO	REVISION	APPROVED BY	DATE
0	ORIGINAL DRAWING	SJC	7/19
1	ADDED BYPASS NOTE	SJC	7/19

QUALIFYING GENERATION INTERCONNECT LESS THAN 40 KW

DWG # ME1M04

ISSUE DATE – JULY 19

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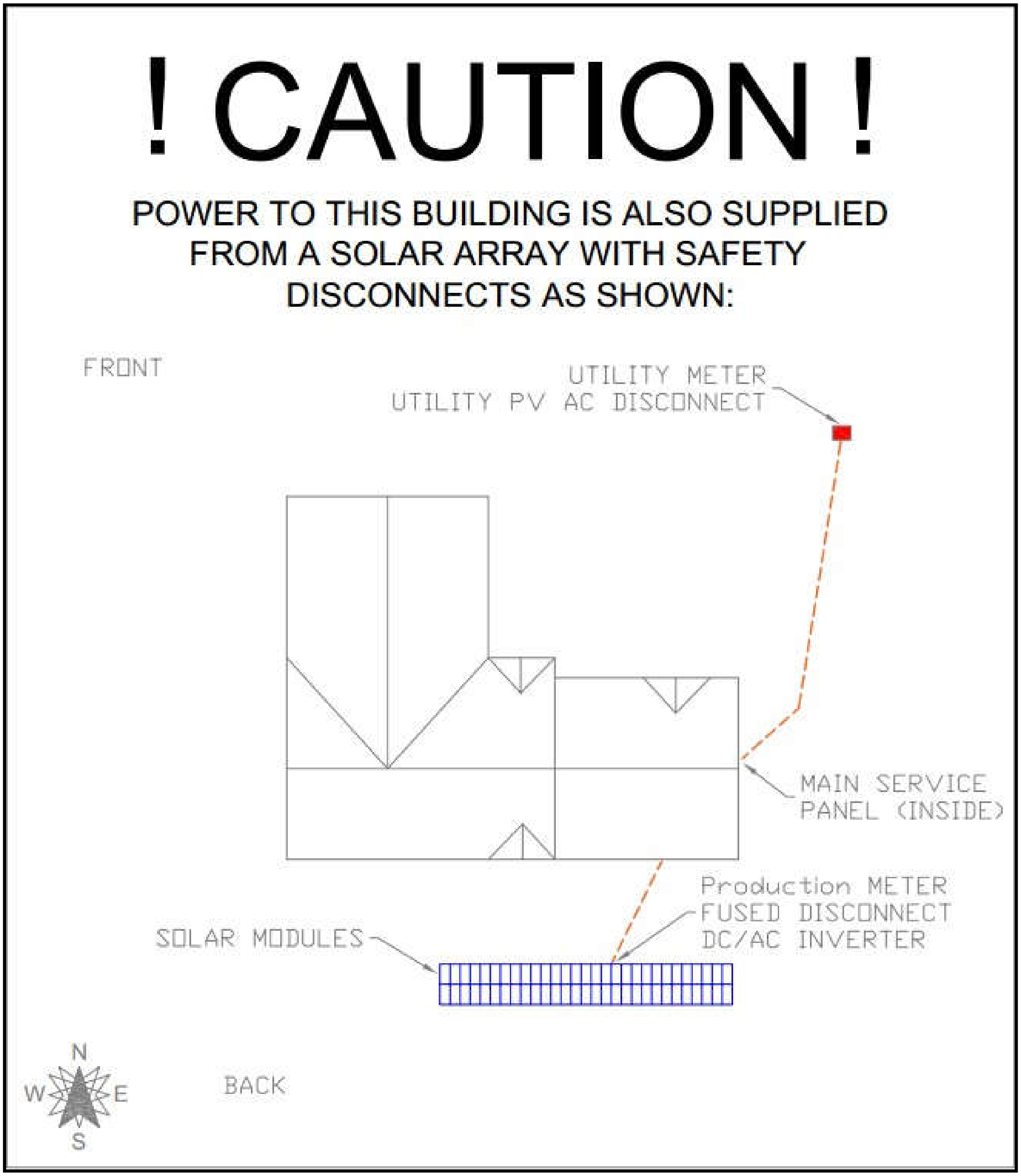
Figure 11. Example Placard



Appendix E – Certificate of Completion

Certification of Completion for RPU

The Interconnection Customer should complete the Distributed Energy Resource Certification of Completion for a proposed DER interconnection in the Simplified Process Track. As a condition of interconnection, a completed copy of this form must be returned to RPU.

Distributed Energy Resource Information		
Interconnection Customer:		
DER Project Address:		
City:	State:	Zip Code:
Application ID:	Meter Number:	
Is the DER system owner-installed?	☐ Yes	☐ No (If no please completed Installer Information)

Installer Information	
Contact Name:	
Name of Business:	
Email:	Phone:
Electrician Name	License #

Electrical Permitting Authority		
The DER has been installed and inspected in compliance with the local electrical permitting authority ☐ Yes ☐ No		
If inverter based DER, the inverters are UL 1741 certified and have been programmed to have:		
☐ Yes	☐ No	Operating Mode set to Constant Power Factor with power factor set at 0.98 absorbing
☐ Yes	☐ No	Frequency Abnormal Response set to IEEE 1547-2003 ranges
☐ Yes	☐ No	Voltage Abnormal Response set to IEEE 1547-2003 ranges
☐ Yes	☐ No	Dynamic Voltage Support and Volt-Watt is not active
Installer Signature:		Date:
Please print clearly or type and return completed along with any additional documentation		

For Office Use Only
Date Received:

Appendix F – Example Simplified Process DER Testing Procedure

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Distributed Energy Resources (DER)
Commission Test Checklist

For RPU personnel use only.

Date: ______________________ **RPU Representative:** ______________________

Address: ____

☐ 1 Customer or customer representative is present for the testing. Three phase customers acknowledge that the system will be tested for loss of phase which may cause single phasing to non-generating equipment and that they accept this risk.

Name of representative: ______________________________________

DER company: ______________________________________

☐ 2 Testing procedure explained to customer or customer representative.

☐ 3 Remote Generator Disconnect(s) installed and labeled properly.

☐ 4 Main meter area signage installed identifying location of remote Generator Disconnect(s), if located other than within 10ft of main meter or within sight.

☐ 5 Disconnect the generator from utility system power and ensure the inverter(s) properly shutdown.

☐ 6 Reconnect the generator to utility system power by closing the disconnect switch and ensure the system does not re-parallel with the utility system for at least 5 minute once the switch was closed.

☐ 7 ***Three phase systems only:***
Disconnect one phase at a time
- ○ All generation stopped after A phase was lost.
- ○ All generation stopped after B phase was lost.
- ○ All generation stopped after C phase was lost.

☐ 8 Production meter socket tested and production meter installed.

Production meter number: ______________________________________

☐ **PASS**

☐ **FAIL**

REASON FOR FAIL: ______________________________________

Appendix F – DER Alteration Notification

This form is only applicable for installed DER systems that have prior approval from the Area EPS Operator to operate in extended parallel. **Changes to capacity size, type, technology or location should be applied as a new application using either the Simplified or Fast Track application forms.** This form is to inform the Area EPS Operator of changes in inverter, control system and protective device settings or the exchange of "like-for-like" DER equipment. The Area EPS Operator may determine the proposed change requires additional review to ensure the operation of the Area EPS is not detrimentally affected. The Area EPS Operator will notify the listed contact if additional details or steps are required. Contact the DER Coordinator for further information.

General Information		
Original Application ID (If known):		
Customer Account Number:		
Address of Generating Facility:		
City:	State:	Zip Code:
Existing DER System		
Current DER Type *(Check all that apply)*:		
☐ Solar Photovoltaic	☐ Wind	☐ Energy Storage
☐ Combined Heat and Power	☐ Solar Thermal	☐ Other (please specify)
Aggregate DER Capacity (the sum of nameplate capacity of all generation and storage devices at the PCC):		
kW_{ac}	*kVA_{ac}*	
Please, in detail, explain the proposed alteration to the DER system: *(Example: Existing inverter was replaced with 9.8 kW AC inverter, Solar Edge Model SE-9800-US. Settings remained the same in the inverter.) (Example: Plan to utilize Time-of-Use control mode of ESS. Also updated to firmware v2.3)*		
Contact for Additional Questions		
Name:		
Company Name:		
Email:	Phone:	

APPENDIX H: PV and Inverter-base DER Ground Referencing Requirements and Sample Calculations

Scope

This document lists technical requirements, and provides sample calculations, for ground referencing of inverter based Distributed Energy Resources (DER) on the Area EPS 4-wire system medium-voltage (MV) electric distribution system. DER units with AC nameplate capacities from 100kW to 10MW are covered in the scope. This document assumes a proper ground reference is being created by either a separate grounding transformer or a wye-grounded:delta (MV:LV) interconnection transformer. Inverters which have an internal grounded-wye isolation transformer are not covered in this document. The information in this document is to be applied at the Point of Common Coupling.

Background

Ground referencing electric distribution systems is standard practice in large part to avoid damaging overvoltages, for line-to-ground connected loads, which can result from ground fault conditions on ungrounded systems. Figure A below shows the range of expected line voltages for different system ground referencing methods. Line surge arrestors and customer equipment connected phase-to-ground are usually not designed to withstand the phase-to-phase voltages that can occur during ungrounded system fault conditions.

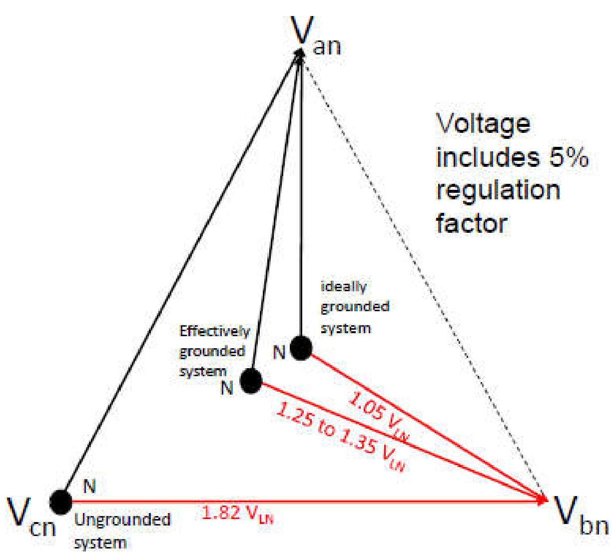

Figure A – Neutral shift during ground fault conditions

During a ground fault condition, in situations where the Area EPS's protective device opens and before the DER trips off-line, the distribution system has lost the system ground reference. It is important that any DER source energizing this portion of the distribution system provides a ground reference in order to prevent overvoltages.

Std IEEE 1547-2013 stated that "the grounding scheme of the DR interconnection shall not cause overvoltages that exceed the rating of the equipment connected to the Area EPS". Std IEEE 1547-2018 states that "The DER shall not cause the fundamental frequency line-to-ground voltage on any portion of the Area EPS that is designed to operate effectively grounded, as defined by IEEE Std C62.92.1, to exceed 138% of its nominal line-to-ground fundamental frequency voltage for a duration exceeding one fundamental frequency period." The below requirements for inverter ground referencing are adopted from IEEE P1547.8/D8- 2014 which is the draft document titled Draft Recommended Practice for Establishing Methods and Procedures that Provide Supplemental Support for Implementation Strategies for Expanded use of IEEE Standard 1547. Although this document as a whole is in draft form and not yet approved, the Area EPS believes the provision below on inverter ground referencing identifies a best practice.

Requirements

For DG Facilities with an Inverter Interface:

1) $X_{0,DG} = 0.6$ p.u. +/- 10%   Note: 1 p.u. is based on $Z_{base} = \frac{kV^2}{MVA_{DER}}$

2) $\frac{X_{0.DG}}{R_{0,DG}} \geq 4$

3) Ground referencing equipment shall be designed to withstand a minimum of $V_0 = 4\%$ and remain connected.

   Note: I_0 can be approximated as $I_0 = \frac{V_0}{Z_0}$

4) Ground referencing equipment shall have 5-second withstand ratings that exceed maximum available short-circuit current for close in faults.

Additional Notes:

a) *Sum of MVA ratings of DER inverter nameplates and high-side (medium voltage) kV rating of interconnection transformer or grounding bank, depending on which unit creates the ground source, are used in determining required zero-sequence impedance ($X_{0,DG}$) for composite facility.*

b) *The MVA and high-side kV rating of the interconnection transformer or grounding bank, depending on which unit creates the ground source, is used for determining grounding bank and neutral reactor sizing.*

c) *The impedance of the interconnection transformer is needed for neutral reactor sizing.*

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Example Calculations

The below examples assume a ground reference is created by a proper transformer configuration and that the PV facility is interconnected to the Area EPS 4-wire electric distribution system. For simplicity, the example online diagrams below exclude system components not relevant to grounding requirements; these drawings are not intended to be used as example onelines for system design.

Example 1 – Separate Zig-Zag Grounding Transformer

A PV facility with 1 MVA inverter total AC nameplate is interconnected to a 13.8kV feeder through a 1 MVA interconnection transformer that does not create a ground reference. A separate zig-zag transformer is connected at 13.8kV to meet ground referencing requirements. (Note: Secondary ground bank connections are also acceptable when the interconnection transformer is wye-grounded:wye-grounded. The kV used for determine Z_{Base} would be 480V in that case.)

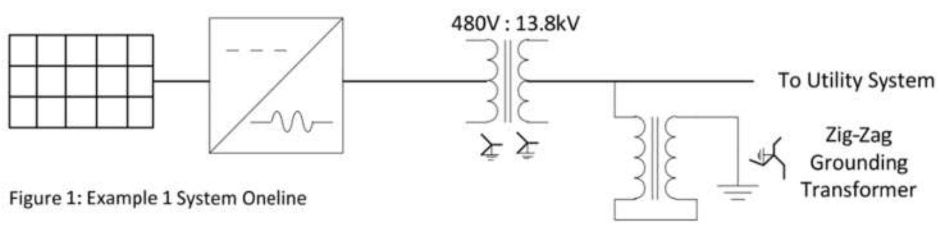

Figure 1: Example 1 System Oneline

1) Find base impedance:

$$Z_{BASE} = \frac{kV^2}{MVA_{pv}} = \frac{13.8^2 kV}{1MVA} = 190\ \Omega$$

Notes: kV is high-side voltage of grounding transformer, MVA_{PV} is aggregate facility (i.e. 5 MVA would be used for five 1 MVA facilities)

Find zero-sequence reactance requirement:

$$X_{0,DG} = 0.6\ (190)\ \Omega \pm 10\% = 114\ \Omega \pm 10\%$$

The zig-zag grounding transformer will require a per phase zero-sequence reactance of 114 Ω ± 10 % to meet Requirement 1.

2) For Requirements 2, verify $\frac{X_{0,DG}}{R_{0.DG}} \geq 4$

3) For Requirement 3, assuming $X_{0,DG}$ = 114 Ω determines the continuous current associated with V_0 = 4%.

Find base current value

$$I_{BASE} = \frac{V_{BASE}}{Z_{BASE}} = \frac{\frac{13.8}{\sqrt{3}} kV}{190\ \Omega} = 41.8\ \text{A}$$

Find per unit zero sequence current

$$I_{0,p.u.} = \frac{V_0}{Z_0} = \frac{0.04}{0.6} = 0.067\ p.u.$$

Fine zero sequence current in amps

$$I_0 = I_{BASE} * I_{0,p.u.} = 41.8A * 0.067 = 2.8\ A$$

Verify that the transformer per phase rating exceeds this value.

Find neutral current

$$I_N = 3(I_0) = 3(2.8)A = 8.4\ A$$

Verify that the transformer continuous neutral rating exceeds this value.

4) For Requirement 4, request system impedance from the Area EPS engineer and determine ground bank's short circuit contribution for close-in single-line to ground faults. The grounding transformer 5-second withstand rating shall exceed the maximum anticipated ground fault current contribution from the transformer.

Example 2 – Wye-grounded: Delta Interconnection Transformer with Neutral Rector

A PV DER facility with a 1 MVA inverter total AC nameplate is interconnected to a 13.8 kV feeder through a 1 MVA interconnection transformer through a wye-grounded:delta interconnection transformer (grounded-wye winding is connected to 13.8 kV system). The interconnection transformer has nameplate impedance of 5%. A neutral reactor is required to meet ground referencing requirements.

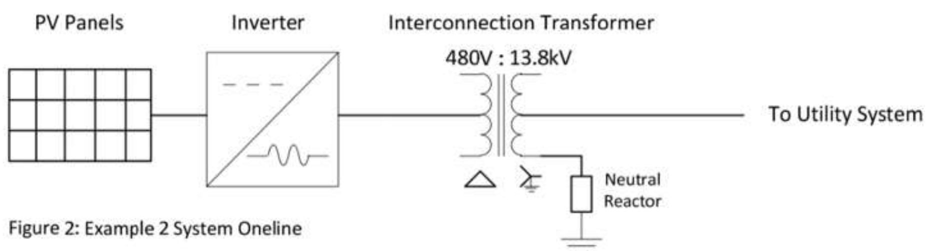

Figure 2: Example 2 System Oneline

1) Find base impedance:

$$Z_{BASE} = \frac{kV^2}{MVA_{pv}} = \frac{13.8^2 kV}{1MVA} = 190\ \Omega$$

Note: kV is high-side voltage of grounding transformer, MVA $_{PV}$ is aggregate facility (i.e. 5 MVA would be used for five 1 MVA facilities)

Find zero-sequence reactance requirement:

$$X_{0,DG} = 0.6\ (190)\ \Omega \pm 10\% = 114\ \Omega \pm 10\%$$

Find interconnection zero-sequence reactance contribution:

$$X_{0,Xfmr} = X_{0,Xfmr,p.u.} * Z_{Base} = 0.05\ (190)\ \Omega = 9.5\ \Omega$$

Find neutral reactor zero-sequence contribution to meet requirement for subtracting interconnection transformer contribution:

$$X_{0,NR} = X_{0,DG} - X_{0,Xfmr} = 114 - 9.5\ \Omega = 104.5\ \Omega \pm 10\%$$

Determine neutral reactor size (note: $I_{Neutral} = 3 * I_{0,Xfmr}$):

$$X_{NR} = \frac{X_{0,NR}}{3} = \frac{104.5\ \Omega}{3} = 34.8\ \Omega\ \pm 10\%$$

A neutral reactor with a reactance of 34.8 Ω ±10%, inserted into the neutral of the interconnection transformer, will meet ground referencing Requirement 1. Requirement 2 through 4 should be checked using transformer nameplate information.

2) For Requirements 2, verify $\frac{X_{0,DG}}{R_{0,DG}} \geq 4$

3) For Requirement 3, assuming $X_{0,DG} = 114\ \Omega$ determines the continuous current associated with $V_0 = 4\%$

Find base current value

$$I_{BASE} = \frac{V_{BASE}}{Z_{BASE}} = \frac{\frac{13.8}{\sqrt{3}}\ kV}{190\ \Omega} = 41.8\ A$$

Find per unit zero sequence current

$$I_{0,p.u.} = \frac{V_0}{Z_0} = \frac{0.04}{0.6} = 0.067\ p.u.$$

Determine zero sequence current in amps

$$I_0 = I_{BASE} * I_{0,P.u.} = 41.8\ A * 0.067 = 2.8\ A$$

Find neutral current

$$I_{NR} = 3(I_0)\ A = 8.4\ A$$

Verify that the neutral reactor continuous rating exceeds this value.

4) For Requirement 4, request system impedance from the Area EPS engineer and determine ground bank's short circuit contribution for close-in single-line to ground faults. The grounding transformer 5-second withstand rating shall exceed the maximum anticipated ground fault current contribution from the transformer.

Example 3 – Separate Wye-grounded: Delta Grounding Transformer

A PV facility with 1MW inverter total AC nameplate is interconnected to a 13.8kV feeder through a 1MVA wye-grounded:wye-grounded interconnection transformer. A separate wy-grounded:delta_transformer is connected at 480V to meet grounding reference requirements.

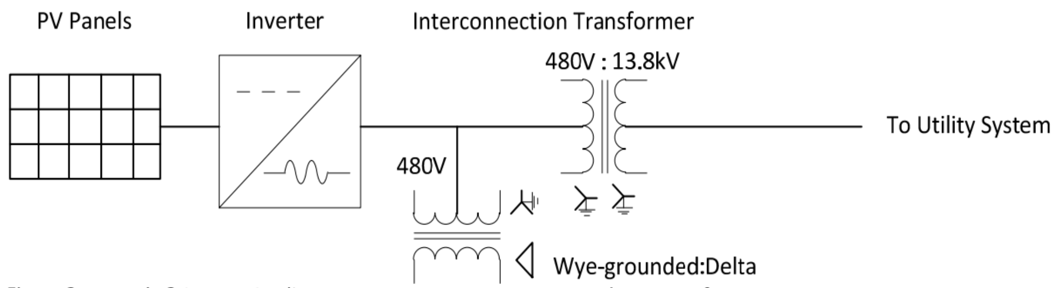

Figure 3: Example 3 System Oneline

1) Find base impedance:

$$Z_{BASE} = \frac{kV^2}{MVA_{pv}} = \frac{0.48^2 kV}{1MVA} = 0.2304\ \Omega$$

Notes: kV is high-side voltage of grounding transformer. MVA_{PV} is aggregate facility (i.e 5MVA would be used for five 1 MVA facilities)

Find zero-sequence reactance requirement:

$$X_{0,DG} = 0.6\ (0.23)\ \Omega \pm 10\% = 0.14\ \Omega \pm 10\%$$

The grounding transformer will require a per phase zero-sequence reactance of 0.14Ω ±10% to meet requirement 1.

2) For Requirements 2, verify $\frac{X_{0,DG}}{R_{0,DG}} \geq 4$

3) For Requirement 3, assuming $X_{0,DG} = 0.14\ \Omega$ determines the continuous current associated with $V_0 = 4\%$.

Find base current value

$$I_{BASE} = \frac{V_{BASE}}{Z_{BASE}} = \frac{\frac{0.48}{\sqrt{3}} kV}{0.2304\ \Omega} = 1202.8\ A$$

Find per unit zero sequence current

$$I_{0,p.u.} = \frac{V_0}{Z_0} = \frac{0.04}{0.6} = 0.067\ p.u.$$

Find zero sequence current in amps

$$I_0 = I_{BASE} * I_{0,P.u.} = 1202.8\ A * 0.067 = 80.6\ A$$

Verify that the transformer per phase rating exceeds this value.

Find neutral current

$$I_N = 3(I_0) = 3(80.6)\ \mathrm{A} = 241.8\ \mathrm{A}$$

Verify that the transformer continuous neutral rating exceeds this value.

4) For Requirement 4, request system impedance from the Area EPS engineer and determine ground bank's short circuit contribution for close-in single-line to ground faults. The grounding transformer 5-second withstand rating shall exceed the maximum anticipated ground fault current contribution from the transformer

R E S O L U T I O N

BE IT RESOLVED by the Public Utility Board of the City of Rochester, Minnesota, to adopt the proposed Technical Specification Manual for Distributed Energy Resources effective on August 1, 2021, and grant staff the ability to make minor changes to the document to keep it current with Minnesota requirements and applicable industry standards.

Passed by the Public Utility Board of the City of Rochester, Minnesota, this 29th day of June, 2021.

____

President

____

Secretary

FOR BOARD ACTION

Agenda Item # **(ID # 13525)** **Meeting Date: 6/29/2021**

SUBJECT: 2021 Electric Service Rules and Regulations

PREPARED BY: Steve Cook

ITEM DESCRIPTION:

RPU has written and published Electric Service Rules and Regulations since the early 1980's. The intent of this document is to provide consistent guidance to customer and electrical contractors in regards to establishing new electric service to a property or to make revisions to an existing electrical service installation to a property.

The current version of the Electric Rules and Regulations was published and adopted in June 2017. RPU staff is attempting to update and revise this document every four (4) years, or as needed. Staff began the revision process for this document in 2020 and just recently completed the review process for the proposed changes. Changes made in the proposed 2021 Electric Rules & Regulations fall under the following major categories:

(1) Updates based on new 2020 National Electric Code (NEC) requirements

(2) Clarifying existing rule requirements and language

(3) Inserting new inspection and installation language

(4) Renumbering and rearranging existing sections to allow for the addition of brand new Section 500 - Distributed Energy Resources (DER) to address interconnection requirements for these systems to RPU's distribution grid

Wording or numbering changes are shown in RED text throughout the document to highlight where the changes occurred.

UTILITY BOARD ACTION REQUESTED:

Staff requests the Utility Board adopt the proposed Electric Rules and Regulations to become effective on July 19, 2021.

ROCHESTER PUBLIC UTILITIES

ELECTRIC SERVICE
RULES AND REGULATIONS

Revised: **July 2021**

INTRODUCTION

Rochester Public Utilities (hereafter referred to RPU) has assembled this booklet to assist its customers and their architects, engineers, or electrical contractors to plan for and obtain electric service. The requirements herein supersede all previous publications of the "Electric Service Rules and Regulations" issued by RPU prior to the above date and is subject to change without notice.

The information presented here is intended to supplement the requirements of the National Electrical Code® (NEC®), National Electric Safety Code® (NESC®), National Fuel and Gas Code (NFPA54), Liquefied Petroleum Gas Code (NFPA58), and all other applicable federal, or state, and municipal codes, regulations, laws and ordinances. It is always necessary to refer to and comply with such other codes, regulations, laws, and ordinances when planning, designing, and installing a new electrical service. Specific requirements of RPU do not intentionally conflict with any other requirements known to be in effect as of the publication date of this booklet. Any apparent conflicts of this nature should be brought to the attention of RPU for interpretation. RPU assumes no responsibility whatsoever for the manufacturer's, supplier's, electrician's, or engineering consultant's compliance with all applicable codes as well as all local and state codes. Any waiver at any time of RPU's rights or privileges under the electric service rules and regulations will not be deemed a waiver as to any breach of other matter subsequently occurring.

All questions or requests should be directed to RPU's Customer Care Department at the contact number or email address listed on page 2.

These electric rules and regulations are available for download from RPU's website https://www.rpu.org/construction-center.php. Contact RPU for more details.

RPU ELECTRIC CONTACT INFORMATION

Main Office Address: 4000 East River Rd NE
Rochester, MN 55906-2813

Web Address: https://www.rpu.org

Contact	Phone Number	Email
Customer Care	507.280.1500	customerservice@rpu.org
Customer Care: Toll Free	800.778.3421	
Emergency Electrical Outages (24 hours)	507.280.9191	
Metering Department	507.292.1232	
Modified or New Service	507.292.1232	newservice@rpu.org

OTHER CONTACT INFORMATION

Contact	Phone Number	Website
GOPHER STATE ONECALL	800.252.1166	www.gopherstateonecall.org
Rochester Building and Safety Department	507.328.2600	

REVISION HISTORY

Revision Date	Brief Description of Revisions
Aug 2011	Starting Revision for tracking
May 2015	Major Revisions
August 2017	Revisions
July 2021	Revisions

TABLE OF CONTENTS

SECTION 100 – DEFINITIONS

Application for Service: The agreement or contract between RPU and the customer under which electric service is supplied and taken.

Accessible: Allowing or admitting, close approach; not guarded by locked doors, elevation, or other effective means including any portion of a temporary or permanent structure.

Approved: Acceptable to the authority having jurisdiction.

Building: A structure with roof and walls. Two (2) or more structures shall not be considered a single building merely by the existence of skyways, tunnels, common heating or cooling facilities, common garages, entry halls or elevators, or other attachments.

Cold Sequence: In a cold meter sequence, a disconnecting device is located on the line side (before) of the metering equipment.

Conduit: Standard tubular material used for mechanical protection of electrical distribution lines which may be exposed, buried beneath the surface of the ground, or encased in a building as required. (See definition for Duct).
NOTE: For the purpose of this document, the terms Conduit and Duct are used interchangeably

Connected Load: The combined manufacturer's rated capacity of all motors and other electric energy consuming devices on the customer's premises which may, at the will of the customer, be operated with the electric energy to be supplied from the service of RPU.

Contractor: Licensed individual or company who performs work on behalf of the customer or RPU.

Current Transformer (CT): An instrument transformer designed for the measurement or control of current.

Customer: Any individual, partnership, corporation, or other legal entity now being served or to be served, using the electric service of RPU at any specified location.

Customer's Service Equipment: The necessary equipment and accessories, located near the point of entrance of supply conductors to a building, which constitute the main control and means of disconnecting the supply to that building. This equipment usually consists of a circuit breaker or a switch and fuses.

Disconnection Means: A device, or group of devices, or other means by which the conductors of a circuit can be disconnected from their source of supply.

Distribution Lines: RPU's lines located along streets, alleys, highways, or easements on private property, when used or intended for use for general distribution of electric service to customers.

Distributed Energy Resource (DER): Often referred to in the past as Distributed Generation (DG) and on occasion also interchanged with the term Qualifying Facility (QF). DER are all types of generation and energy resources that can be interconnected to RPU's electric distribution system. DER technologies can include photovoltaic solar systems, wind turbines, storage batteries, or fossil fuel generators are not limited to renewable types of technologies.

Distributed Generation (DG): Distributed Energy Resources that are derived from a generation source, not from energy storage.

Duct: Standard tubular material used for mechanical protection of electrical distribution lines which may be exposed, buried beneath the surface of the ground, or encased in a building as required. (See definition for Conduit).
NOTE: For the purpose of this document, the terms Conduit and Duct are used interchangeably

Dwelling:

> **Dwelling Unit**: One or more rooms for the use of one or more persons as a housekeeping unit with space for eating, living and sleeping, and permanent provisions for cooking and sanitation.
>
> **Multi-Family Dwelling**: A building containing two or more dwelling units.
>
> **Single-Family Dwelling**: A building consisting solely of one dwelling unit.

Easement: The right of use over and under the property of another, such as a right-of-way.

Electric Service: The availability of electric power and energy, regardless of whether any electric power and energy is actually used. The supplying of electric service by RPU consists of the maintaining, at the point of delivery, approximately the agreed voltage, phase and frequency by means of facilities adequate for carrying the load which RPU is thereby obligated to supply by reason of the known requirements.

Excess Facilities: Those instances where RPU provides distribution and/or metering facilities at the customer's request, in excess of the facilities RPU deems necessary to supply service to the customer.

Fault Current: The current that will flow through the system to a point where a piece or a conductor has failed, such as bare conductors touching together or a bare conductor touching a ground point.

Frost (Frozen Ground): A condition where the water contained within the ground freezes, resulting in additional difficulty and expense in excavation work.

Hot Sequence: In a hot meter sequence, there is not a disconnecting device located on the line side (before) the meter.

Individual RPU Metering: Direct measurement by RPU, using a RPU meter, of all electrical consumption of a customer supplied by the company.

Instrument Transformer: A transformer that reproduces in its secondary circuit, the voltage or current proportional to its primary circuit.

Instrument Transformer Cabinet: A cabinet installed and owned by the customer, complying with RPU's requirements, and designed for housing instrument transformers used for metering.

Junction Cabinet: A pad-mounted enclosure where underground primary cables are connected together, either by splices or separable connectors, for underground distribution systems.

Master Metering: Metering configuration where a single meter (Master meter) measures the consumption for a building, and then sub-meters on the Customer side of the Master Meter measure the consumption of individual load, loads, or groups of loads.

Meter/Meter Set: An instrument or instruments, together with auxiliary equipment for measuring the electric power and energy supplied to a customer.

National Electrical Code® (NEC®)[1]: The current edition of the National Electrical Code as issued by the National Fire Protection Association (NFPA No. 70).

National Electric Safety Code® (NESC®)[2]: The current edition of the National Electric Safety Code as issued by the Institute of Electrical and Electronics Engineers (IEEE® C2), American National Standards Institute (ANSI® C2).

Nominal Voltage: The value, expressed in volts, which is assigned to a circuit or system for the purpose of conveniently designating its voltage class (such as 120/240V, 277/480Y, etc.). The actual voltage at which a circuit operates can vary from the nominal within a range established by ANSI C84.1. The customer is responsible for making sure that their systems are capable of operating within range B of ANSI C84.1.

Occupancy Unit: A room, office, apartment, or other space separated by walls or partitions that enclose the area, or a contiguous grouping thereof when occupied by a single customer.

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[1] National Electrical Code® and NEC® are registered trademarks of the National Fire Protection Association, Inc., Quincy, MA 02269

[2] National Electric Safety Code® and NESC® are registered trademarks and service marks of the Institute of Electrical and Electronics Engineers, Inc. New York, NY 10017

Paved: A surface covered with a material such as stone, asphalt, or concrete designed for vehicular traffic.

Point of Delivery: The point where the electric energy first leaves the line or apparatus owned by RPU and enters the line or apparatus owned by the customer. This is not necessarily the point of location of RPU's meter.

Point of Interconnection: The location designated by RPU that the Customer must extend conduits to in order for RPU to install our facilities on customer property.

Primary Service: Any type of service with a nominal voltage greater than 600 volts.

RPU: Rochester Public Utilities

Rate Schedules: The classification of the use of electricity into categories considering the amount of power supplied and the purpose of its use.

Redistribution: The provision of unmetered electrical supply by a customer to customer's tenants or other occupant, or to any person who qualifies for unmetered service.

Redundant Facilities: Duplicate (partial or full) facilities installed at the request of the customer for the purpose of increasing reliability of the system for a particular customer.

Secondary Connection Cabinet: Cabinet required when the number and/or size of the conductors exceeds RPU's limit for terminating in a specific pad-mounted transformer. If a secondary connection cabinet is used, it will also be the location of the metering equipment.

Secondary Service: Any type of service with a nominal voltage less than or equal to 600 volts.

Secondary Terminal: The secondary side of a pad-mounted transformer, service pedestal, or vault, whichever is designated by RPU.

Series Subtractive Metering: An arrangement to measure consumption in a multiple occupancy unit building using individual RPU meters on each occupancy unit in series with one RPU master meter to measure total building consumption on the set of service entrance conductors or feeder supplying the individual occupancy units with billing for common area usage determined by company formula.

Service: The conductors and equipment for delivering energy from RPU's system to the wiring system of the customer.

Service Drop: The overhead service conductors from the last pole or other aerial support up to, and including the splices (if any), connecting to the service-entrance conductors at the building or other structure.

Service Entrance Conductors, Overhead System: The service conductors between the terminals of the service equipment and a point usually outside the building, clear of building walls, where joined by tap or splice to the service drop.

Service Entrance Conductors, Underground System: The service conductors between the terminals of the service equipment and the point of delivery.

Service Equipment: The necessary equipment, usually consisting of a circuit breaker or switch and fuses, and their accessories, located near the point of entrance of supply conductors to a building or other structure, or an otherwise defined area, and intended to constitute the main control and means of cutoff of the supply.

Service Upgrade: An electric service is considered upgraded if any of the following conditions are met:

- If the rating of the customer disconnect is increased
- If the main service disconnect type is changed (i.e. from fuses to a circuit breaker)
- If either the conductors between the meter socket and the customer disconnect or the conductors on the supply side of the meter are changed
- A new DER system is installed by the customer

Sub-metering: The provision of metered electrical supply through a customer owned meter to a customer's tenants, cooperative or condominium owners, other occupants, or to a portion of the customer's own electrical consumption.

Underground Residential Distribution (URD) Areas: Those residential subdivisions, or other specified areas, within which all customers are served by underground distribution lines.

Underground Service Lateral: The secondary service conductors from RPU's distribution system.

Unsuitable Backfill Material: Includes, but is not limited to, the following materials:

- Granular material (individual stones, soil in clumps or clods, etc.) larger than ¼" in diameter
- Frozen materials
- Materials removed as rock excavation or over-excavation
- Trash, metal, or construction waste
- Environmentally contaminated soils

Utility: For the purpose of this document any public, city, or city-franchised organization that furnishes electric service.

Voltage to Ground: For grounded circuits, the voltage between the given conductor and that point or conductor of the circuit that is grounded; for underground circuits, the greatest voltage between the given conductor and any other conductor of the circuit.

Voltage Transformer (VT): An instrument transformer intended for use in the measurement or control of a circuit and designed to have its primary winding connected in parallel with the circuit.

SECTION 200 – GENERAL INFORMATION

201 SERVICE JURISDICTION

RPU has been established by the City of Rochester for the purpose of providing electricity to the residents of the City. RPU also provides electricity to residents outside of the City limits but within the service area boundaries established by the State of Minnesota. Service will be provided to all eligible applicants only when all applications, agreements, easements, deposits, payments, and other required information have been provided to RPU.

202 APPLICATION FOR SERVICE

Application for initial, additional, or temporary electric service must be made by the customer, or a designated representative, to RPU. Applications can be made at RPU's Service Center or by contacting a Modified or New Service Representative (refer to page 2 for contact information). At the time of application, the customer will be required to provide, in writing on the form(s) provided, information relating to the service request, including the following:

(1) Exact location of premises to be served, including building street address, apartment or unit number if applicable, lot and block numbers, and name of subdivision

(2) The type of service desired (e.g. temporary, permanent, residential subdivision, dwelling unit, commercial, industrial, rewire, etc.)

(3) The approximate date that electric service is required

(4) The name, address, and telephone number of the customer's designated representative who will be responsible for working with RPU representatives in providing the electric service (e.g. customer, employee, engineer, contractor, etc.)

(5) Commercial Services:

a) Load Data Sheet: The customer, or their representative, shall submit to RPU's Engineering Department a completed Electrical Load Data sheet specifying the type of service required by the customer and expected magnitudes of connected and peak load. Additional data in the form of construction drawings and the proposed service entrance may also be necessary for RPU to adequately determine the capacity and arrangement of service to the customer. The completed Load Data sheet must be received before RPU can perform the necessary planning and design of the project. Failure to provide this information at the start of a project may result in significant delay in RPU being able to provide service

b) The Commercial Service Application must be submitted as soon as feasible in order for RPU to establish an account, and allow adequate time to invoice and receive payment for the Line Extension Fee, if applicable

c) Notification to RPU Engineering that the customer is ready for installation of the transformer must be received a minimum of ten (10) working days prior to energizing the service

RPU should be advised of planning installations as early as possible so that details for furnishing service may be arranged and construction completed by the desired date. Application forms and additional information may be obtained at https://www.rpu.org/construction-center.php. Contact a RPU Modified or New Service Representative (refer to page 2 for contact information) with questions concerning the application process.

203 OWNERSHIP OF EQUIPMENT

203.1 RPU-Owned Equipment - The meter and associated metering equipment furnished or installed by RPU are the property of RPU.

(1) Overhead Service – In addition to the metering equipment, the overhead service drop installed by RPU is the property of RPU

(2) Underground Service – In addition to the metering equipment, all equipment up to and including the designated point of delivery is the property of RPU

203.2 Customer-Owned Equipment - The meter socket, instrument transformer compartment (if required, see Section 610), the service entrance conductors and conduit from the meter socket to the service entrance disconnect, the service entrance switch or circuit breaker, the service entrance ground equipment, and the concrete transformer pad and grounding grid are the property of the customer.

(1) Overhead Service – In addition to the equipment on the customer side of the meter socket, the service drop wire holder or bracket, the weather head, and either the service mast and conduit with entrance wires, or the service entrance cable with watertight connection to the meter socket are the property of the customer

(2) Underground Service – In addition to the equipment on the customer side of the meter, all conduit and cable required to extend the secondary service lateral from RPU's point of delivery to the meter socket are the property of the customer

203.3 Responsibilities - The customer and RPU are responsible for the installation, maintenance, repair, and replacement of the electric service equipment which each owns.

204 EASEMENTS

Whenever any RPU-owned underground and/or overhead material and equipment is located above or below the customer's property, the customer shall grant an easement to RPU to the extent which RPU deems necessary. All utility easements required by RPU are to be granted by the customer at no cost to RPU.

204.1 Easement Legal Description and Exhibit Processes

(1) Rochester Community Development – When the easement is sought during the Rochester Community Development process, the customer or property developer shall provide the legal description and exhibit by a Registered Land Surveyor

(2) Other Easement Request – When the easement is sought after the property has been developed, RPU will provide an electronic copy of the assembled easement (legal description and exhibit by a Registered Land Surveyor) for the property owner's signature. Once sign-off by the property owner is received by RPU, RPU will record the signed easement paperwork

204.2 Change of Grade - The finished grade in any platted or recorded utility easement shall not be altered without first contacting RPU Engineering to determine if electric facilities are installed within the easement. Permission may be granted to change the finished grade by RPU Engineering if the proposed grade change will not affect minimum burial depth requirements for ducts or require removal and reinstallation of above grade facilities such as transformers, poles, secondary pedestals, etc. Replacement and/or relocation of RPU facilities, at customer's expense, may be required if necessitated by the proposed grade change. RPU Engineering will provide a cost estimate for all work associated with the proposed grade change for approval prior to the commencement of any proposed grade change work. Payment must be received and cleared prior to the start of any work by RPU.

205 INSPECTION OF CUSTOMER'S FACILITIES

205.1 Requirements – As a minimum, wiring and electrical equipment of the customer shall be installed in accordance with the latest edition of the National Electrical Code®.

205.2 Inside City Limits – Customer services and associated wiring installations located within the Rochester city limits, including temporary installations, must be inspected and approved by an authorized inspector of the City Building Safety Department as required by Minnesota Statutes Section 326.B.36. RPU will make connection only after approval by the authorized inspecting authority. The inspector is required by Minnesota Statutes Section 326.B.36 to disconnect or have disconnected by the utility any installation that is declared by the inspector to be unsafe and a hazard.

205.3 Outside City Limits – Customer services and associated wiring installations located outside the Rochester city limits and requesting service from RPU must have their wiring inspected by a state inspector. RPU will make connection before authorization from the state inspector only if the master electrician who installed or supervised the installation agrees in writing to be responsible for said wiring until such time that it can be inspected and approved by the state inspector ("Request for Electrical Inspection" – white form).

205.4 Disconnected Service Inspection – For any electric service that has been disconnected for more than ninety (90) days prior to a reconnection request, the customer will be required to hire a licensed electrical contractor to perform an inspection of the building or dwelling's electrical wiring to verify that no unsafe or hazardous conditions are present prior to RPU re-energizing the service.

Exception:
Multi-family dwellings that have 6 meters or more installed, with at least one (1) meter in the ganged service entrance energized, are exempt from the above requirement

205.5 Other Required Inspections (Forms can be found at https://www.rpu.org/construction-center.php)

(1) Transformer Pad – Prior to pouring concrete, the customer, or customer's contractor, shall complete and submit to RPU's Engineering Department the completed "Request for Transformer Pad Inspection" form, with multiple photos. RPU personnel will review the photos and visually inspect the formed pad within the timeframe noted on the form. Observed deficiencies will be communicated to the contact listed on the submitted inspection form. **Corrections and re-inspection by RPU personnel must be made before approval to pour concrete will be given**. RPU reserves the right to refuse service if the transformer pad is poured prior to inspection and correction of noted deficiencies

(2) Subdivision Installation – The customer, or customer's contractor, shall complete and submit to RPU's Engineering Department the completed "Developer Request for Utility Installation in Subdivisions" form. The site will then be inspected for compliance with requirements. If no deficiencies are found, the site will be scheduled for joint utility installation. If any deficiencies are found, corrections must be made and a new form re-submitted for inspection prior to the site being scheduled for joint utility installation

206 SERVICE CONNECTION, DISCONNECTION & RECONNECTION

206.1 Site Readiness – After the customer's installation has been inspected and approved by the proper authority, a meter will be installed by RPU and the electric service made available provided that all applications, fees, agreements, and deposits have been submitted by the customer and approved by RPU. Inspection notices must be received by RPU two (2) business days prior to the date that the connection is desired (weekends and holidays excluded). Under special circumstances, verbal inspections will be accepted as long as written inspection documentation is submitted immediately thereafter.

206.2 Notification – Customer requests for disconnection or reconnection of existing services must be received by RPU two (2) business days prior to the desired time of disconnection or reconnection (weekends and holidays excluded). For the mutual protection of the customer and RPU, only authorized employees of RPU are permitted to set and remove meters, or to make and energize or break and de-energize the connection between RPU's service drop or secondary terminals and the customer's service entrance conductors or underground service laterals.

206.3 Building Demolition – If a building is scheduled for demolition, the contractor shall notify RPU's New Services Department for a service disconnect a minimum of two (2) business days prior to the start of demolition. RPU will then issue a work order to disconnect the service. There is no RPU charge for the retirement of electric service.

If at some future time the owner at the location requires service, the owner shall be required to submit a new "APPLICATION FOR SERVICE" request, pay any and all liens or amounts encumbered by RPU and/or any outstanding RPU charges before an account will be reactivated.

206.4 Commercial Customer Requested Outage – Customer shall contact their Commercial Account Representative. Contact information can be found at https://www.rpu.org/contact-us.php or by calling the RPU Customer Care number listed on page 2 of this document.

207 LIABILITY

207.1 Damage as Result of Service – RPU does not engage in the practice of doing interior wiring on the customer's premises except for the installation and maintenance of its own property, and therefore, is not responsible for service beyond the point of delivery. RPU shall not be liable for damage to any customer or to any third party resulting from the use of the service or from the presence of RPU appliances or equipment on the customer's premises.

207.2 Responsibility – The customer is solely responsible for any accidents, fires, or failures resulting from the condition and use of his wiring installation or equipment.

208 SERVICE INTERRUPTIONS

208.1 Notice – RPU reserves the right to interrupt service at any time. Interruptions for maintenance and system improvements will be prearranged and advance notice will be given to the customer whenever practical.

208.2 Responsibility – RPU will not be responsible for consequential damages resulting from service interruptions or fluctuations outside its control or from operations in response to abnormal system conditions. Customers requiring service reliability and/or stability exceeding RPU's normal service should consider uninterruptible power supplies, isolation transformers, power conditioners, redundant services, or other options to provide the level of service needed. RPU's Engineering Department is available to discuss such needs.

209 ACCESS

Employees of RPU shall have the right of access to the customer's premises at all reasonable times for the purpose of installing, reading, inspecting, maintaining, or removing any of its meters, devices, or other equipment which is used in connection with the furnishing of the customer's electric service.

210 CUSTOMER RESPONSIBILITY

Failure of the Customer to notify RPU in a timely manner of any planned alteration to electric service facilities or increased electrical load, and failure to comply with RPU's published rules, regulations, and rate schedules may result in delayed connections, interruption of service, or damage to equipment, for which RPU disclaims all responsibility.

211 REVISIONS OF REQUIREMENTS

All requirements stated or implied herein are subject to change at any time without prior notice.

SECTION 300 – STANDARD SERVICES

301 GENERAL CHARACTERISTICS

This section describes the types of services offered to customers under RPU's standard rate schedules. Electric service supplied by RPU is alternating current having a nominal frequency of 60 Hertz (cycles per second).

302 AVAILABILITY OF SERVICE

Although the types of service listed in subsequent sections are generally available through the area served by RPU, service of the type requested by a customer may not be available at the location where such service is desired, and in certain cases may be available only through special contractual arrangements and at the expense of the customer. Each customer will generally be allowed only one type of service and one point of delivery for each location.

302.1 Redundant Services – Refer to Section 404 for requirements.

302.2 Multiple Services – Only one (1) service installation to a customer's service equipment is allowed. During customer renovation or service upgrade work, should RPU determine that a customer's service equipment has multiple services connected to it, RPU Engineering will work with the customer to eliminate the multiple service installation as soon as possible.

303 SECONDARY SERVICE VOLTAGE

The following types of secondary service are generally available to customers served under RPU's standard rate schedules:

303.1 Single Phase Service – 120/240 Volt, 3-Wire, Grounded Neutral: Generally available where the total load is 100 kVA or less for pad-mount service, or 50 kVA or less for pole-mounted service, with an underground secondary in each case

303.2 Three Phase Service – Generally available where facilities of adequate capacity are adjacent to the premises to be served

(1) 208Y/120 Volt, 4-Wire, Grounded Neutral: Generally available to customers with loads determined by RPU to be 75 kVA or greater for pad-mount service, or 45 kVA or greater for pole-mounted service with an underground secondary in each case. The maximum size pad-mounted transformer that RPU will install for this service voltage is 1000 kVA

(2) 240/120 Volt, Delta, 4-Wire, Grounded Neutral: No longer available as a new standard service

(3) 240 Volt (and 480 Volt), Delta, 3-Wire: No longer available as a new standard service

(4) 480Y/277 Volt, 4-Wire, Grounded Neutral: Generally available to customers with loads determined by RPU to be 75 kVA or greater for pad-mount service, or 45 kVA or greater for pole-mounted service with an underground secondary in each case. The maximum size pad-mounted transformer that RPU will install is 2500 kVA

303.3 New Development Cost Calculation – Refer to RPU Line Extension Policy. Any costs assessed to the project by RPU will need to be paid by the customer prior to RPU performing facility installation.

303.4 Redevelopment Cost Calculation – Contact RPU's Engineering Department for determination of cost (if any) that will be assessed to the project by RPU.

304 PRIMARY SERVICE VOLTAGES

Three-Phase, 13800Y/7970 Volt, 4-Wire, Grounded Neutral Service: Available only by special request where the total annual peak load at one site is projected by RPU to exceed 500 kW. RPU reserves the right to deny a request for a primary voltage service. Where provided, the point of delivery will normally be the terminals of RPU's cable in the customer's switchgear.

SECTION 400 – SPECIAL SERVICES

401 TEMPORARY SERVICE REQUIREMENTS

401.1 General – Temporary service is intended to be supplied at secondary voltages only to customers for use during the construction of permanent facilities and before the permanent service can be installed.

401.2 Address – The address of the location to be supplied with temporary service must be permanently displayed at the location and on the temporary pedestal/meter location and be easily readable from the street before RPU will install the temporary service. All overhead and underground temporary services will be metered and billed under one of RPU's standard rate schedules.

401.3 Installation – The customer shall provide an approved meter socket with the necessary raceway and a suitable rigid support for attachment of the metering equipment and service drop. On all three phase temporary services, where required, the customer shall also provide a suitable enclosure for installation of RPU's instrument transformers.

401.4 Installation Length – Service to any electrical installation for a period of less than two (2) years shall be considered as "temporary service". Any installation that remains in service longer than this timeframe must be changed to a permanent service installation when directed by RPU.

401.5 Fees - Temporary electrical services costs shall be in accordance with the following requirements listed below:

(1) Secondary Available at Property:

a) A temporary meter installation fee will be assessed for the first single phase temporary service installed for construction. The location of the temporary service will be designated by RPU

(2) RPU has primary voltage facilities available on or adjacent to the lot and setting of a transformer is required:

a) A temporary meter installation fee and a temporary facilities installation fee will be assessed for the first temporary service installed for construction. The location of the temporary service will be designated by RPU

(3) RPU does not have adequate facilities in the area:

a) The customer will be required to pay RPU for the actual cost to install and remove the temporary service(s)

(4) Information regarding the charges for temporary service can be obtained from RPU Engineering. RPU may require temporary service fees to be paid in advance.

402 SERVICES FOR UNUSUAL LOAD CHARACTERISTICS

402.1 Customer Transients – The operation of customer equipment having a relatively high load of short or intermittent duration, such as welders, compressor motors, elevators, and X-ray equipment, may cause serious fluctuations of voltage and interfere with the service being provided by RPU to other customers. If such a load is anticipated, the customer must consult with RPU and agree to install such protective devices as may be required so as not to cause damage to any of RPU's equipment or in any way inhibit service to other customers.

402.2 Special Compensation - Special compensation may be required by RPU, from the customer, in those cases where it is necessary for RPU to install non-standard, or larger, facilities than would normally be required to provide satisfactory service. (Refer to Section 700 for additional details).

403 EXCESS FACILITIES

RPU will size utility electric facilities (primary cable and transformer) to serve the load projected by RPU. If a customer desires RPU to install excess facilities, RPU must be advised as soon as possible so the feasibility of such a service can be determined. If RPU determines that excess facilities can and will be provided, the customer will be required to reimburse RPU for the difference in cost between the standard service and the excess facilities, including all labor, materials, and overheads. A written agreement between the customer and RPU shall also be executed at RPU's discretion.

404 REDUNDANT FACILITIES

RPU will provide one set of facilities (such as a set of primary cables and a transformer) to one point of service for each customer. If a customer requires redundant facilities (more than one set of facilities to the same point of service), RPU must be advised as soon as possible so the feasibility of such service can be determined. If RPU determines that redundant facilities can and will be provided, the customer will be required to reimburse RPU for the entire cost of additional facilities, including all labor, materials, vehicle charges, and overheads. An agreement between the customer and RPU may also be executed at RPU's discretion.

405 IN-BUILDING TRANSFORMER VAULT INSTALLATIONS

405.1 Availability – In-Building transformer vault installations are allowed within the core downtown area of Rochester only. Contact RPU's Engineering Department to determine if a project falls within this defined area, and to obtain the construction standard with requirements. Additional fees and agreements between the customer and RPU will be required for this type of transformer installation.

406 RELOCATION OR PROTECTION OF RPU FACILITIES

406.1 Responsibilities – It is the responsibility of the customer to arrange for the relocation and/or protection of RPU's facilities whenever such action is appropriate. Any intended relocation or protection of RPU's facilities must be reviewed with and approved by RPU in advance.

406.2 Customer Costs – The cost of any change or relocation of RPU's facilities for the benefit only of the customer, and which has been initiated by the customer, shall be borne solely by the customer. A deposit by the customer may also be required before the changes are made.

406.3 RPU Costs – RPU will bear costs to the extent that a change or relocation benefits RPU. The customer shall not be required to pay for changes necessitated through public improvements by the City, County or State.

406.4 Painting – The customer shall not paint or otherwise modify the appearance of any RPU owned equipment or facilities.

407 REWIRING OR UPGRADING EXISTING FACILITIES

407.1 General – The customer or electrical contractor shall contact RPU when it is necessary to rewire or upgrade an existing electric service. All RPU Electric Service Rules & Regulations must be followed. The customer shall be responsible for maintaining the same phase rotation for 3-phase rewires.

407.2 Not Permitted – Customers shall not be allowed to convert an existing underground electric service to an overhead service.

407.3 Underground Service – When a customer with an existing RPU owned underground service lateral upgrades the conductors of their service, the ownership of the underground service lateral will transfer from RPU to the customer. Other changes or upgrades that don't affect the underground service lateral conductor size will not cause the ownership to transfer.

SECTION 500 – DISTRIBUTED ENERGY RESOURCES

501 GENERAL INTERCONNECTION REQUIREMENTS

The State of Minnesota has interconnection process standards in effect to address interconnection of distributed energy resources (DER) to the distribution grid. Rochester Public Utilities has process and technical requirements that meet the State standards. The customer shall follow RPU's process for projects to install, modify existing, and operate generating equipment interconnected with RPU's distribution system. No generation equipment shall be allowed to operate interconnected to RPU's distribution system without prior approval from RPU and meeting all requirements of RPU, the State of Minnesota, and all other applicable regulations and standards.

502 TECHNICAL REQUIREMENTS

A copy of RPU's rules, technical requirements, process documentation, and applications for operation of Distributed Energy Resources are available through RPU's website https://www.rpu.org. If the DER is under 10 MW in size, it will follow the appropriate State of MN mandated process. If the DER size is over 10 MW, contact RPU's Engineering Department for guidance prior to starting design.

SECTION 600 – METERS AND METERING EQUIPMENT

600 GENERAL

This section covers the installation of meters and associated equipment such as current and potential transformers for both overhead and underground services. Further description of RPU requirements for both overhead and underground services is covered in other sections of this booklet. The requirements contained in this section are for services rated 600 volts or less. When services are required at primary voltage (such as 13800Y/7970 volts), the metering requirements and equipment will be determined on an individual basis.

601 METERING EQUIPMENT RESPONSIBILITIES

All metering equipment, with the exception of the meter, current and potential transformers, must be purchased and installed by the customer or electrical contractor. All metering equipment installed must be certified and labeled and have prior approval of RPU's Electric Metering Department. Metering equipment installed without RPU approval will not be energized unless special permission from RPU's Electric Metering Department is obtained. RPU will energize only one (1) set of metering equipment under each contract or application for one class of service.

602 LOCATION OF METERS

602.1 General – Meter locations will be agreed upon by representatives of the customer and RPU, subject to final approval by RPU.

602.2 Clearances – Meters shall be installed in a location with not less than three (3) feet of unobstructed space in front and 30 inches total in width. Meters shall not be located where they are subject to corrosive fumes, dust, vibration or physical damage. Outdoor meters shall not be located in carports, under porches whether open or enclosed, or along walkways or driveways where they might create a hazard to people or be subject to damage by passing objects. Required meter working and safety clearances are shown in Section 1200, Exhibit 11.1.

602.3 Accessibility – Meter locations shall not be hazardous or cause inconvenience to employees of RPU when installing, maintaining, or reading the meters. RPU personnel shall have direct and unobstructed access to RPU's metering equipment at all times. Recessed meter socket installations shall not be permitted.

602.4 Height Limits - All meters located outdoors on residential, industrial, or commercial services, where the meter is mounted on a permanent structure, shall have a maximum installation height of 5'-0" and a minimum installation height of 3'-0" from final grade to the center of the meter. A typical residential underground service meter installation is shown in Section 1200, Exhibit 1.

602.5 Residential – Residential meter installations shall comply with the following requirements:

(1) All new services must have the electric meter located outside

(2) Existing residential customers where the meter is located inside shall relocate the meter to the outside during a service upgrade as defined under Section 100 Definitions

(3) Any service upgrade or DER installation requires the existing meter socket to be changed to an approved self-contained lever bypass type (if non-compliant)

(4) All new self-contained meter sockets installed under (1), (2), or (3) above must be on the list of approved meter sockets (refer to Section 613)

602.6 Multi-Family Dwelling – Where more than one meter is installed (typical for apartment complexes), meters shall be grouped outdoors at a point accessible at all times to each customer and to RPU personnel.

Exceptions:

a) Multi-family dwellings that have 24 meters or more may request to locate the meters inside as long as they are grouped at one (1) location and accessible at all times to each customer and to RPU personnel

b) Multi-family dwellings where the building has over three (3) occupied stories fully above grade, the customer may request in writing for permission to be allowed to install grouped metering panels in multiple locations. The metering locations should be minimized and typically would only be allowed on every 3rd story of the building

In all cases where multi-metering panels with stacked meter sockets are used, the maximum height to the center of the top meter shall be not more than 6'-0" indoors and 5'-0" outdoors and the minimum height to the center of the bottom meter shall be not less 1'-0" indoors and 3'-0" outdoors. Individual apartment disconnects must be connected on the load side of the meter. If the service voltage is 120/208 volts, a fifth terminal located at the 9 o'clock position is required in the socket and must be connected to the service neutral in accordance with the National Electric Code® (Refer to Section 1200, Exhibit 11.0). The house meter socket for apartment buildings requires an approved lever actuated positive bypass mechanism which will provide clamping pressure on the meter blades. Only one (1) meter may be installed under one socket cover in multi-metering panels

RPU will set a minimum of one floor of meters at a time. Meter service charges will start at the time of the meter set.

602.7 Mobile Homes - RPU will individually meter each mobile home located in a mobile home court or addition to a mobile home court. Resale of metered electrical energy by the court owner will not be permitted in these facilities. Individual meter pedestals, with bypass sockets, shall be provided by the customer or his representative. Maintenance and repair of the meter pedestal is the responsibility of the customer. A typical mobile home metering arrangement is shown in Section 1200, Exhibit 2.

602.8 Industrial and Commercial – Industrial and Commercial self-contained meter installations shall comply with the following requirements:

(1) All new services must comply with the requirements of Sections 602.1 through 602.4 listed above

(2) Any service upgrade or DER installation requires the existing meter socket to be changed to an approved self-contained lever bypass type (if non-compliant)

(3) All new self-contained meter sockets installed must be on the list of approved meter sockets (refer to Section 613)

602.9 Commercial Multi-Metering Panels – Installations shall comply with the following requirements:

(1) All commercial multi-metering panels used in shopping centers, spec. buildings, and multi-commercial tenant buildings shall have a maximum of four (4) meter sockets per vertical stack. In all cases, the maximum height to the center of the top meter shall be not more than 6’-0” indoors and 5’-0” outdoors and the minimum height to the center of the bottom meter shall be not less 1’-0” indoors and 3’-0” outdoors. An approved lever bypass is required on all meter sockets and each individual unit disconnect shall only be connected to the load side of the meter. Each individual meter socket shall have a barrier to isolate the customer’s disconnect switch and wiring from the metering area. Only one (1) meter may be installed under one socket cover. A system neutral is required to each 5 and 7 terminal meter socket in accordance with the National Electric Code®

(2) Each meter shall have a separate accessible lockable service disconnect wired in cold sequence to be used by RPU

Exception:
In situations where the building has over three (3) occupied stories fully above grade, the customer may request in writing for permission to be allowed to install

grouped metering panels in multiple locations. The metering locations should be minimized and typically would only be allowed on every 3rd story of the building

603 GROUPED METERS

In installations requiring more than one meter, the meters shall be grouped and suitably connected such that a meter serves no more than one customer. The height limits stated previously also pertain to grouped meters where practicable. If deemed necessary by the space available, the meters may be stacked in an orderly fashion. Any dwelling with more than one customer living therein must have an individual meter for each dwelling unit. These meters must be easily accessible to all tenants and to RPU personnel. There shall be an approved type of disconnecting means for each meter, which is lockable in some way to prevent reconnection by other than RPU personnel. A typical multiple metering arrangement is shown in Section 1200, Exhibit 3.

604 METER IDENTIFICATION

604.1 Requirements – If more than one meter is required for a building, each meter socket shall be identified and permanently designated in a suitable manner indicating the particular customer served. An engraved hard plastic tag will be required with ½ inch block letters or numbers. The tag shall be securely attached to the exterior, non-removable portion of the meter socket and at the individual meter main disconnect. Any other means of identification is not acceptable. **Meters will not be installed until the above requirements are met.**

604.2 Circuit Checking – Each circuit shall be carefully traced and rechecked by the customer or contractor to ensure against errors in wiring that would result in one customer obtaining service through the meter serving another customer. This is especially important when the wiring is concealed. Electric service shall not be energized if meter sockets are not identified. It will be the contractor's/owner's responsibility to correct any errors due to misidentification of meter sockets. RPU reserves the right to charge the building owner and/or electrical contractor for actual costs incurred by RPU to make corrections.

605 METER MOUNTING

605.1 Outdoor Meters and Meter Mounting Devices – Outdoor meters and meter mounting devices shall be mounted securely on permanent structures such as houses, garages, and other buildings. Where outdoor meters are installed on surfaces that prevent installation of the meter-mounting device in an exact vertical plane, a meter board must be installed or the surface modified in such a manner that the meter-mounting device can be installed vertically.

605.2 Preferred Meter Location(s) – The preferred meter location is within ten (10) feet of the front end of the building (house or attached garage) on a single-family dwelling for new customer hook ups. All meter locations for rewired or upgraded services shall be located outdoors with locations agreed upon between customer, contractor, and RPU personnel with final approval by RPU personnel. RPU has the right to refuse to energize service if these requirements have not been met.

605.3 Indoor Meter Location(s) – Indoor meters, where permitted, shall be mounted in accordance with the preceding requirements of this section and shall be located as close as possible to the point where service enters the building. Indoor metering equipment shall be mounted securely in a vertical plane on permanent structures in a location free from moisture, high temperature, vibration, dust, or dirt.

606 METER CONNECTIONS

606.1 General – The customer shall provide the necessary wiring for the meter set with the wiring so arranged that the line (supply) side can be connected to the top terminals of the socket and the load side to the bottom terminals. All conductors shall extend into the meter socket and shall be of equal length and at a minimum distance equal to the length of the socket trough. All neutral conductors must be insulated.

606.2 Underground Services – Underground service installations shall comply with the following requirements:

(1) Line side neutral wire shall be identified in accordance with the National Electrical Code®

(2) An expansion joint shall be furnished and installed by the customer on all new underground residential meter installations. The expansion joint shall be a minimum eighteen (18) inch length Schedule 80 PVC installed at the bottom of the meter housing

(3) Sufficient slack should be left in the underground cables to make up for any ground shifting due to settling or extreme cold

607 WIRING RESTRICTIONS ON METERS & METERING SETS

607.1 General – Meters and metering sets shall comply with the following requirements:

(1) No customer wiring shall be permitted to be connected to the metering, secondary wiring, or under the terminals of the meter

(2) No part of the metering set shall be used as a junction box for the customer's wiring

(3) No non-RPU owned equipment shall be permitted to be installed between the self-contained meter and the customer-owned meter socket.

608 METER TESTING

608.1 Testing Request – Any customer, who believes that a meter is failing to register properly the use of electricity, may request a meter check by contacting an RPU Customer Care Advisor. RPU will test the meter using standard calibration equipment and generally accepted test procedures within a reasonable period of time. Customers who request additional meter tests within a twelve (12) month period may be charged for the additional tests at a standard fee.

608.2 Meter Error Standard – Whenever a watt-hour meter is found upon test to have an average error of more than two percent (2%) from one hundred percent (100%) or a demand meter more than one and one-half percent (1.5%) from one hundred percent (100%), a recalculation of bills for service will be made on the basis that the meter should be one hundred percent (100%) accurate with respect to a working test standard.

608.3 Meter Inaccuracy (Working) – If the period of inaccuracy cannot be determined, it will be assumed that the metering equipment has become inaccurate at a uniform rate since it was installed or last tested unless there is a valid reason to use another method. Recalculation of bills is based upon RPU Board Policy for adjustments of customer accounts.

608.4 Meter Inaccuracy (Failure) – When the average error cannot be determined by test due to complete failure of all or part of the metering equipment, then an estimate of the quantity of energy consumed based upon available data will be used to determine the adjusted bills.

609 METER SEALS

All connections to RPU service equipment shall be made by RPU Electric Metering Department personnel only. Unauthorized connections to or tampering with any RPU meter, associated equipment or meter seals, or indications or evidence thereof subjects the customer to immediate discontinuance of service, prosecution under the laws of Minnesota, adjustment of prior bills for services rendered, and reimbursement to RPU for all extra expense incurred on the account. In addition, when the unauthorized connections or tampering involve an inside meter, the customer shall, at his own expense, relocate all service equipment and metering facilities outside the building.

610 INSTRUMENT TRANSFORMER METER INSTALLATIONS

RPU no longer furnishes instrument rated meter sockets. Please contact a local electrical distributor of your choice to purchase an RPU approved instrument rated meter socket. If requiring an 8 terminal meter socket, please contact RPU's Electric Metering Department for prior approval.

610.1 Where Required – It will be necessary for RPU to use instrument transformers in the metering installation under the conditions listed below:

(1) Single Phase Service: When any single phase service exceeds 320 continuous amps in size or exceeds 240 volts

(2) Three Phase Service: When any three phase service exceeds 320 continuous amps in size or exceeds 240 volts

610.2 Instrument Transformer Provision & Location – All instrument transformers will be furnished by RPU and installed by RPU's Electric Metering Department, or delivered to the customer/contractor to install into an approved instrument transformer cabinet. The instrument transformer cabinet will be located before the customer service entrance disconnect switch.

610.3 Secondary Metering Instrument Transformer Cabinet Requirements – Cabinet shall be furnished and installed by the customer. This includes all services, either overhead or underground. All cabinets must be certified and labeled, approved by RPU personnel and meet all National Electric Code® requirements prior to installation. All cabinets must conform to the following:

(1) The meter socket shall not be mounted to the door of the cabinet

(2) Cabinets must be UL approved and be the correct NEMA class for the area environment in which it is installed

(3) Minimum instrument transformer cabinet sizes are as follows:

a) 250 volts and below: 48 inches high, 25 inches wide, and 15 inches deep

b) 251 – 600 volts: 48 inches high, 36 inches wide, and 15 inches deep

(4) The door must have a single closure with provisions for locking with a standard padlock through the handle

(5) Cabinet must be hinged on the right or left side only

(6) Cabinet shall not be used as a junction box or service connection cabinet

(7) Only RPU metering transformers may be contained therein

(8) A 1-inch conduit installed between the cabinet and meter socket location is required

(9) Cabinet must accept bar-type current transformers on all services 1200 amps or less

(10) Customer is required to label the line side and load side of the conductors within the instrument transformer cabinet

610.4 New Service Secondary Metering Requirements – For any new electrical services requiring the use of instrument transformers, the instrument transformers must be mounted in an approved instrument transformer cabinet complying with the requirements of 610.3 above and be located as follows:

(1) Underground Service from Pad-Mounted Transformers: When service is supplied underground from a pad-mounted transformer, the location of the instrument transformer cabinet must be approved by RPU during installation

(2) Overhead Services: When service is provided by overhead service drops, approved outdoor instrument transformer cabinets will be required. Location of transformer cabinets will have final approval by RPU's Electric Metering Department before installation. No open air CT's or PT's will be allowed

(3) Indoor Mounted Instrument Transformers: Instrument transformers installed indoors must have a service size of 1200 amps or greater, be installed inside the customer switchgear in a compartment designated for instrument transformers only, and have prior approval from RPU's Electric Metering Department

610.5 New Indoor Primary Metering Equipment Requirements

(1) When primary metering service is to be installed, the customer shall furnish a compartment or switchgear cubicle to house the primary current and potential instrument transformers. All current and potential instrument transformers shall be rated for metering accuracy as approved by the RPU's Electric Metering Department. The metering point shall be located electrically between the customer's main disconnect and customer's circuits ("cold sequence" metering arrangement

(2) When practical, RPU may request that the customer install the primary current and potential transformers per RPU specifications. (Contact a Customer Care Advisor to obtain Engineering assistance.)

610.6 New Outdoor Primary Metering Equipment Requirements – When outdoor primary service is to be installed, RPU may elect to utilize either a pole-mounted or pad-mounted primary metering equipment set. Outdoor primary metering units are furnished and installed by RPU. Sharing of the material and installation costs for primary metering will be determined on a case-by-case basis.

610.7 Existing Service Emergency Repairs – In situations requiring emergency repairs to an existing electrical service where instrument transformers are installed in any location other than an instrument transformer cabinet, the customer/contractor must receive prior approval for the new mounting location of the current transformers from RPU's Electric Metering Department. These types of installations include, but are not limited to:

(1) Instrument transformers mounted on a pole

(2) Instrument transformers installed inside a distribution transformer

(3) Instrument transformers installed inside customer switchgear

611 SELF-CONTAINED METER INSTALLATIONS

611.1 Requirements – In general, RPU will install self-contained meters (meters without instrument transformers) on single or three phase services (240V or less) where the service rating is 400 amps or less (Class 320 meter socket). Where such metering is to be used, the customer shall provide a ringless lever-operated bypassing socket (Refer to Section 613). Such meter sockets permit a continuation of service upon removal of the meter for testing or maintenance. If a lever-operated bypass meter socket is not installed, the service will not be energized.

612 MASTER METERING INSTALLATIONS

612.1 All new residential units will be individually metered.

Exception Provided in Minnesota Rule 326B.106 Subd. 12:
Buildings intended for occupancy primarily by persons who are 62 years of age or older or disabled, supportive housing, or buildings that contain a majority of units not equipped with complete kitchen facilities, shall be exempt from the provisions of this subdivision. For purposes of this section, "supportive housing" means housing made available to individuals and families with multiple barriers to obtaining and maintaining housing, including those who are formerly homeless or at risk of homelessness and those who have a mental illness, substance abuse disorder, debilitating disease, or a combination of these conditions."

(1) A customer claiming the above exception above takes all legal responsibility for proving the exemption for the life of their building

(2) Any customer claiming the exception above must provide RPU, in writing, a statement that they are claiming an exception under Minnesota Rule 326B.106 Subd. 12 and why they feel their building meets the requirements for an exception. RPU does not determine the validity of the claimed exception and this required filing is for RPU's documentation only

612.2 All new commercial or industrial units will be individually metered. Exceptions must be approved by RPU's Electric Metering Department.

612.3 Sub-metering by others for the purpose of charging individual occupants based on measured use must be in accordance with statutory requirements. Sub-metering by others for information purposes or to control the use of electric power for energy is permitted.

613 APPROVED METER SOCKETS

Meter installations made with unapproved meter sockets will not be energized, or subject to disconnection if non-approved equipment is installed. Refer to the table on the following page for a list of meter sockets approved for installation by RPU.

RPU APPROVED METER SOCKETS		
SELF CONTAINED	SERVICE VOLTAGES	APPROVED MFG./PART NUMBER
4 Terminal 100A to 320A, Lever Bypass (Residential, 1-Phase)	120V, 2 wire Single Phase OR 120-240V, 3 wire Single Phase OR **(240/480V, 200A MAX)**	Milbank: U3791, U5844, or U6281 Series GE: TSMB Series Siemens/Talon: UAPB, UAPC, UAP, 4040, 4760, UAB, or LGMN Series Eaton-Cutler Hammer: MBX or CMBX Series
5 Terminal 100A to 320A, Lever Bypass (Residential, 1-Phase)	120V, 2 wire Single Phase OR 120-208V, 3 wire Single Phase OR 120-240V, 3 wire Single Phase Network	Milbank: U3791 or U6281 Series GE: TSMB Series Siemens/Talon: UAPB, UAPC, UAP, 4040, 4760, UAB, or LGMN Series Eaton-Cutler Hammer: MBX or CMBX Series
7 Terminal 400A MAX, Lever Bypass (Commercial, 3-Phase)	120-208V 4-Wire-WYE OR 120-240 4 Wire-DELTA **(This service is not allowed for new installations)**	Milbank: #U4701-RRL Series Eaton-Cutler Hammer: MBX, CMBX, UTE7213BCH Series Siemens/Talon: UAPB, UAPC, UAP, 4040, 4760, UAB or LGMN Series
INSTRUMENT RATED	SERVICE VOLTAGES	APPROVED MFG./PART NUMBER
6 Terminal Over 400A and larger (Residential or Commercial, 1-Phase)	120-240V, 3 wire Single Phase	Milbank: #UC7478-RL-WC-271 **(Pre-wired to RPU spec.)**
8 Terminal Over 200A and larger (Commercial 3-Phase)	120-240 3 Wire-DELTA	Contact RPU for approval
13 Terminal 100A and larger (Commercial, 3-Phase)	120-208V, 277-480V 4-Wire-WYE OR 120-240 4 Wire-DELTA **(This service is not allowed for new installations)**	Milbank: #UC7445-RL-WC-951 **(Pre-wired to RPU spec.)**

614 SERVICE AT 480 VOLTS

All 277/480V metering services will require the installation of CT's and VT's. RPU will supply and install all metering CT's and VT's at no cost to the customer/contractor.

Exception:
Self-contained services (200A or smaller) supplying roadway lighting operating at 240/480V and fed from a single phase transformer only supplying the lighting service shall be exempt from the above requirement

615 LOCATION OF HIGH-LEG IN METER SOCKET ON 240/120 VOLT, 3-PHASE SERVICES

The conductor with the higher voltage to ground must be connected to the terminal on the right side. The high-leg conductor must be identified as required by the National Electric Code®. Meter sockets with the high-leg in the wrong position will not be energized. Incorrectly wired sockets will be subject to disconnection until wiring is corrected.

616 REMOVING RPU SEALS AND METERS

Disconnection of RPU metering equipment and cutting of seals is not allowed.

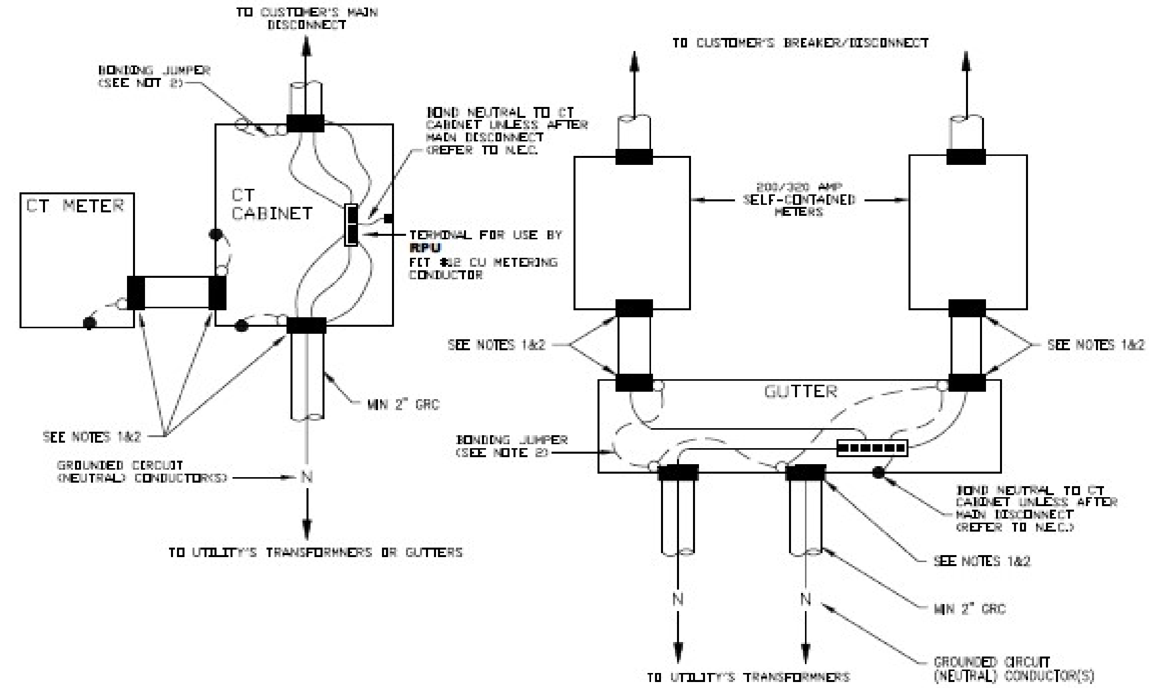
617 CUSTOMER GENERATION

Refer to Section 500 – Distributed Energy Resources for metering requirements pertaining to DER facilities interconnected to RPU's distribution system.

618 PROPER GROUNDING/BONDING OF METER SOCKETS & SERVICES

618.1 Proper Grounding/Bonding – Service equipment and enclosures may need to carry heavy fault currents in the event of a ground-fault. For this reason, it is imperative that meter sockets and conduits be adequately bonded to the neutral and to the ground. Bonding is to be done by threaded couplings and threaded bosses in a rigid metal conduit system where the joints will be made up wrench tight. Locknuts and bushings do not fulfill the requirement of bonding at service equipment. Grounding bushing (with bonding jumpers), bonding locknuts, threaded conduit hubs, or other means are approved (Refer to National Electric Code® Article 250). All metering conduits and sockets must be properly grounded. If PVC conduits are used, grounding conductors must be provided and installed by the customer or electrical contractor in accordance with the National Electric Code®. Electric services will not be connected if improperly grounded/bonded upon inspection. Refer to the Typical Grounding/Bonding for CT Cabinet and Gutter drawing below for additional details:

TYPICAL GROUNDING/BONDING FOR CT CABINET AND GUTTER



NOTES:

1. The metal conduit raceway (PVC is allowed on the load side of the meter socket or CT cabinet) shall be bonded to the neutral conductor by the use of a grounding bushing (with bonding jumper), bonding locknuts, threaded conduit hub.

2. When a grounding bushing is used, a bonding jumper shall be installed to connect with the bonded enclosure. The bonding jumpers shall be sized to meet NEC Table 250.102(c)(1). Bonding to be completed by contractor.

SIZE OF LARGES SERVICE ENTRANCE CONDUCTOR OR EQUIVALENT AREA FOR PARALLEL CONDUCTORS		SIZE OF BONDING JUMPER CONDUCTOR
COPPER	ALUMINUM OR COPPER-CLAD ALUMINUM	COPPER
#1/0 or smaller	#3/0 or smaller	6
#2/0 or #3/0	#4/0 or 250 kcmil	4
Over #3/0 thru 350 kcmil	Over 250 kcmil thru 500 kcmil	2
Over 350 kcmil thru 600 kcmil	Over 500 kcmil thru 900 kcmil	#1/0
Over 600 kcmil thru 1100 kcmil	Over 900 kcmil thru 1750 kcmil	#2/0
Over 1100 kcmil	Over 1750 kcmil	#3/0 or 12 ½% of conductor kcmil, whichever is larger

3. All neutral conductors shale be terminated in CT cabinets and gutters to a common connection.

618.2 Neutral for 5 and 7 Terminal Sockets - A system neutral is required to each 5 and 7 terminal socket. Conductor should be sized in accordance with the National Electric Code®.

619 CUSTOMER DISCONNECT SWITCH

619.1 Location – Disconnect switches shall be installed in a location that meets the same requirements for location as those for electric meters (Refer to Section 602)

619.2 Residential Customers – Individual Customer disconnect switches shall be connected on the load side of the meter. No customer devices, e.g. surge suppressors, load management equipment, etc., may be installed on the line side of the meter.

619.3 Non-residential Customers – Each installation must have a separate securable disconnect, installed on the load side of the meter, and accessible to RPU at all times. If the building is a multi-tenant building, each non-residential customer must have a separate securable disconnect installed on the load side of the meter. The securable disconnect shall be labeled and mounted adjacent to the meter location.

620 SPECIAL SOCKETS

All special sockets, such as ganged meter sockets and free-standing metering pedestals, must have RPU Engineering approval prior to installation.

621 RPU OWNED EQUIPMENT

Any metering equipment furnished by RPU, such as meters, instrument transformers, relays, totalizers, test switches, etc., remain the property of RPU. If the equipment has to be removed or disconnected for any reasons, please call RPU so that the equipment can be picked up.

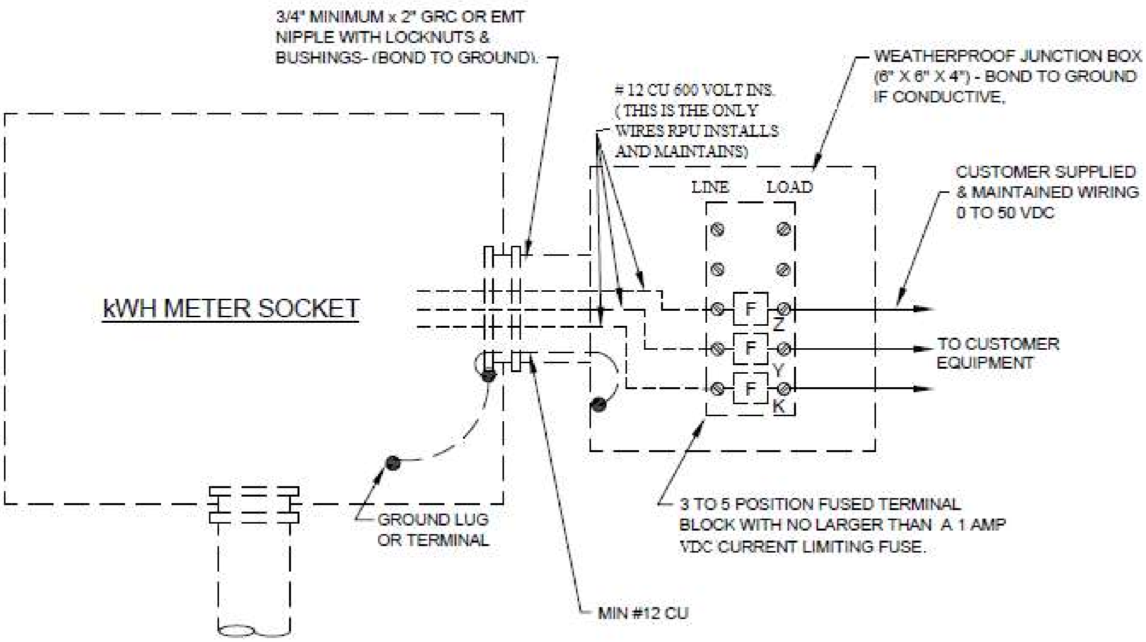
622 TEMPORARY REMOVAL OF CUSTOMER OWNED METER SOCKETS

Any meter socket removal request will be at the discretion of RPU's personnel. Should RPU's personnel not be able to perform the work, it will be up to the customer to hire an electrician/contractor to perform the task. If at any time safety is a concern, RPU will have the service de-energized to perform the work. The customer/contractor shall contact RPU two (2) business days in advance to schedule the temporary removal of the meter socket for siding purposes.

623 PULSE INITIATING DEVICE

Upon the customer's request, the customer/contractor will install a pulse-initiating device on a customer's existing meter socket. To initiate a request for a pulse-initiating device, the customer shall contact RPU. The customer should submit, in writing, all technical information concerning the customer's load-monitoring equipment to RPU. RPU will determine what type of pulse and the amount of pulses available in a given time interval. The customer/contractor will install a weatherproof junction box, a 3 to 5 position fused terminal block, a 3/4 inch galvanized rigid conduit with ground wire from the meter socket to the weatherproof junction box. The customer will furnish, install and maintain all necessary equipment. This wiring will be in accordance with the requirements of the electrical code governing such installation with RPU stipulation that one-amp current limiting fuses be installed on the load side of the terminal block. RPU will then install pulse-initiating device and wiring from the meter socket to the terminal block. Note: RPU's responsibility and liability ends at the line side of the terminal block. **RPU reserves the right to interrupt pulses at any time in order to test or change the meter and to change the pulse value whenever it becomes necessary to upgrade the metering equipment. Every effort will be made to notify the customer when it becomes necessary to interrupt pulses for equipment maintenance. The customer will be notified of any change to the pulse values.**

CUSTOMER CONNECTIONS FOR
PULSE-INITIATING DEVICE INSTALLATION



PULSE INITIATING DEVICE INSTALLATION

SECTION 700 – CUSTOMER UTILIZATION EQUIPMENT

The customer's service entrance and utilization equipment shall be installed in accordance with all local, state, and National Electrical Code® requirements. It is the intent of this section to provide the customer with recommendations concerning factors that can affect both RPU and the customer in the selection, installation, maintenance, and operation of the customer's utilization equipment. If concerns arise that are not covered in this section, please contact a RPU Customer Care Advisor for assistance.

701 PROTECTION OF CUSTOMER EQUIPMENT

701.1 General – The customer is advised to provide adequate protection against the effects of outages or voltage spikes in accordance with the National Electric Code® or other pertinent sources of information for all types of motors and other equipment. Equipment that should be protected includes, but is not limited to:

(1) Motors

(2) Computers

(3) Electronic Equipment

(4) Equipment in which computers or electronics form an integral operating part

701.2 Protection Conditions – Equipment should be protected under all conditions, including:

(1) Overload

(2) Voltage Loss

(3) High or low voltage

(4) Phase loss (e.g. single phasing on polyphase motors)

(5) Re-establishment of service after any of the foregoing

(6) Phase reversal

(7) Motors that cannot be subjected to full voltage on starting

(8) Harmonics or wave form irregularities

701.3 Failure to Protect – Failure to provide such protection may result in needless damage to equipment and the expense of delay and repair.

701.4 Sensitive Electronics – Sensitive electronics, such as microprocessor-based home electronics and business computers, are susceptible to damage due to voltage spikes or surges. Before any microprocessor-based electronics are installed:

(1) Wiring practices that meet manufacturer specifications need to be assured (e.g. proper grounding and dedicated circuits are important)

(2) Consideration should be given to installation of transient voltage surge suppression

a) At the main service entrance

b) At the point of use

(3) An uninterrupted power supply (battery backup) should be considered if a momentary voltage dip or outage would cause loss of data

702 MOTOR STARTING CURRENTS

702.1 General – Typically, all motors require a starting current substantially greater than their normal running current. Where starting currents are excessive, an abnormal drop in supply voltage will result. In order to minimize the unfavorable effects of such voltage drops, it is essential that the customer's motors do not exceed the allowable starting characteristics as shown in Table 430-251(A and B) of the National Electric Code®.

NOTE: Customers planning to install any motor larger than 5 HP single phase or 25 HP three phase, must contact a RPU Engineering. Motor installations that cause power quality problems for other customers shall be corrected at the owner's expense.

702.2 Voltage Flicker – RPU uses IEEE Standard 141 (IEEE Red Book) as a guideline for the level of allowable flicker. Customers are not allowed to start any load on RPU's system that produces unacceptable levels of flicker which affect other customers. Customers are responsible for correcting unacceptable flicker problems in a timely manner when notified by RPU.

703 POWER FACTOR

703.1 Requirements – In order to improve the efficiency of RPU's distribution system, the customer's utilization equipment shall maintain an average power factor as close to unity as possible.

703.2 Penalties – Some of RPU's rate schedules include a demand charge and a penalty for an average power factor that is less than 95%. Details of the method of billing for such customers can be obtained from an RPU Customer Care Advisor. For new services, it is suggested that the customer's utilization equipment be designed for operation at high power factor or with capacitors that are switched on and off with the equipment. Refer to Section 1109, Table 11.1 for correcting customer's power factor.

703.3 Calculation – RPU will calculate the power factor of customers in designed rate classes by installing a varhour meter. Refer to Section 601 for customer's responsibilities in providing metering equipment.

704 FAULT CURRENTS

The customer's service equipment and other devices shall be adequate to withstand and interrupt the maximum available fault current. For single-family residences with service equipment rated 200 amperes maximum and 120/240 volts, single phase, equipment shall have a minimum interrupting rate of 10,000 amperes symmetrical and other equipment shall be braced to withstand that minimum value. Refer to Section 1003 for more information.

705 WIRING ADEQUACY

The National Electrical Code® (NFPA No. 70) specifies the adequacy of wiring with respect to safety; however, such installations may not be efficient or adequate for future expansion of electrical use.

706 CUSTOMER-OWNED GENERATING EQUIPMENT

Unless authorized by written agreement, electric generating equipment installed by the Customer shall not be interconnected or operated in parallel with RPU's distribution system. The customer shall own, install, operate, and maintain electrical interlocking equipment which will prevent parallel operation and such equipment shall be approved by RPU prior to installation.

706.1 Distributed Energy Resources (DER) – For generation and storage systems designed to operate in parallel with RPU's distribution system, refer to Section 500 for requirements governing this type of installation.

707 CUSTOMER'S OBLIGATIONS

707.1 Increased Load – In the event the customer desires to increase load materially, such as adding electric heat, increased motor loads, etc., they shall give RPU sufficient advance notice, so that RPU may provide added facilities if necessary. If the customer fails to notify RPU and RPU's equipment is damaged as a result of such increased load, the customer shall reimburse and make payment to RPU for all such damages.

707.2 Balancing of Load – Except in the case of three-phase, four-wire delta services, the current unbalance in three-phase services shall not exceed 10 percent of the current that would be required at maximum load under balanced conditions.

707.3 Total Harmonic Distortion (THD) Requirements

(1) Nonlinear Load – The application of any nonlinear load by the customer (e.g. static power converters, arc furnaces, adjustable speed drive systems, etc.) shall not cause voltage and/or current Total Harmonic Distortion (THD) levels greater than industry accepted levels on RPU's electric system at the point of power delivery to the customer's facility (Refer to IEEE Standard 519)

(2) Nonlinear Load Disclosure – the customer shall disclose to RPU all nonlinear loads prior to connection. RPU may test the customer's load to determine the THD levels

(3) Nonlinear Load Responsibilities – It shall be the responsibility of the customer to assure that the THD requirements are met, including the purchase of necessary filtering equipment. Any load found not in compliance with this policy shall be corrected immediately by the customer at the customer's expense. If not corrected, RPU may disconnect service to the customer's facility

(4) Nonlinear Load Damages – The customer shall be liable for all damages, losses, claims, costs, expenses and liabilities of any kind or nature arising out of, caused by, or in any way connected with the application by the customer of any nonlinear load operating with maximum THD levels in excess of the values stated in Section 707.3(1) above. The customer shall hold harmless and indemnify RPU from and against any claims, losses, costs of investigation, expenses, reasonable attorney's fees, damages and liabilities of any kind or nature arising out of, caused by, or in any way connected with the application by the customer of any nonlinear load operating with maximum THD levels in excess of the values stated in Section 707.3(1) above

SECTION 800 – OVERHEAD SECONDARY SERVICES

RPU will supply overhead secondary service (600 volts or less), in areas where overhead facilities are available, at the voltages and under the conditions specified in other sections of this publication. The service entrance location will be specified by RPU. This section includes information on distribution transformer size, overhead service drop, and connections to the customer's premises or equipment. Metering and customer equipment requirements are covered in other sections of this publication. The requirements of this section apply to all residential, commercial, and industrial customers.

801 MAXIMUM TRANSFORMER SIZE

801.1 Maximum Size – The maximum standard overhead transformer size installed by RPU will be either one 50 kVA transformer for a single-phase application or three 15 kVA transformers for multiphase applications. If a larger transformer size is required for a particular application, it shall be a pad-mounted type.

801.2 Number of Secondary Services – One (1) or more secondary services may be supplied from a transformer; the number of services from a transformer shall be determined by RPU depending upon the application.

802 SERVICE DROP CONDUCTORS

802.1 New Services – The service drop for new services will be a twisted wire triplex (3 wires) or quadruplex (4 wires) configuration from the distribution system to the point of attachment on the customer's premises.

802.2 Existing Services – The service drop may either be a twisted wire or open wire configuration. If necessary for various reasons, RPU may change a service from an open wire to a twisted wire configuration.

803 CLEARANCES

803.1 Required Clearances (Roofs, Balconies & Windows/Doors) – The service drop must be so located that the minimum clearance as specified in the latest editions of the National Electrical Code® and the National Electric Safety Code® are maintained. Illustration drawings of the clearances required are shown in Section 1200, Exhibits 4, 4.1, and 4.2. Please contact RPU's Engineering Department if there are any questions about the clearances depicted. RPU will not energize an electric service with an observed clearance violation.

803.2 Required Clearances (Patios, Pools & Hot Tubs) – Service drop conductors must be located so that the minimum clearance as specified in the latest editions of the National Electrical Code® and the National Electric Safety Code® are maintained. Illustration drawings of the clearances required are shown in Section 1200, Exhibits 4.3, 4.4 and 4.5. Please contact RPU's Engineering Department if there are any questions about the clearances depicted. RPU will not energize an electric service with an observed clearance violation.

804 POINT OF ATTACHMENT

804.1 Buildings – A solid point of attachment for supporting the service drop on the building shall be provided by the customer at a point which will comply with previously stated clearances in Section 803. Where the required heights and clearances cannot be maintained by a point of attachment on the building, the customer shall provide a service mast which is of a permanent nature and of sufficient strength to support the service drop at the required minimum clearance. Illustration drawings of the attachment clearances and service mast installations are shown in Section 1200, Exhibits 6 and 6.1. In such an installation, 2-inch or larger galvanized iron conduit or 3-inch or larger rigid aluminum conduit shall be used. RPU reserves the right to decline to connect its service drop to an extension support, which, in its judgment, constitutes a hazard to life or property.

805 SERVICE ENTRANCE

805.1 Location – The customer's service entrance wiring shall terminate at a point so located that the service drop from the supply lines will not interfere with windows, doors, awnings, drainpipes, or other parts of the building or other obstructions so that only one bracket is required.

805.2 Customer's Responsibility – Customer's portion of the service entrance shall consist of conduit from the meter socket, a weather head, and wire. Tails shall be left on the customer's service wires extending a minimum of three (3) feet beyond the weather head. The neutral wire shall be identified and shall be continuous (no cut) from the weather head to the entrance switch (unless otherwise approved by RPU).

SECTION 900 – UNDERGROUND SERVICES

901 NEW RESIDENTIAL DEVELOPMENTS

901.1 Point of Delivery – RPU will designate a point of delivery for the connection of the customer's secondary underground service. The point of delivery may be the secondary terminals of a pad-mounted transformer, service pedestal, or secondary vault. In general, RPU will install, own, operate, and maintain all facilities on the source side of the point of delivery, including the junction cabinet and connections; the customer will install, own, operate, and maintain all secondary cables, conduit, and related service equipment specified in other sections of this publication on the load side of the point of delivery.

901.2 Point of Delivery Location – Points of delivery will be located within RPU's easement area along or near a front or rear property line unless it is necessary or desirable to designate locations which are closer to the metering point(s). In such cases, the customer will be charged for the installed cost of any additional lengths of underground distribution cable and conduit from the property line to the point of delivery. Such charges shall be in addition to any other charges specified herein.

901.3 Responsibilities – Additional information regarding RPU and customer responsibilities for URD installations is provided in Section 1200, Exhibit 9.

902 RESIDENTIAL UNDERGROUNDING IN OVERHEAD AREAS

902.1 Customer Initiated – Customers residing in residential zones presently served by overhead lines may request underground electric service. Customers intending to relocate, upgrade, or replace an existing overhead service may request underground service. In either situation, the customer shall own, operate, and maintain the facilities specified in Section 901 above.

902.2 Additional Customer Responsibilities – Customers replacing an existing overhead service with an underground service will install the service conductors to an RPU installed secondary pedestal. The location of the pedestal will be determined by RPU. The customer should contact RPU's Engineering Department for more details prior to proceeding.

903 UNDERGROUND SERVICE TO COMMERCIAL & INDUSTRIAL CUSTOMERS

903.1 Where Required – RPU requires the underground installation of primary and secondary distribution service to new commercial and industrial structures.

903.2 Point of Delivery – RPU will designate a point of delivery for the connection of the customer's secondary underground service lateral. The point of delivery will normally be the secondary terminals of a pad-mounted transformer placed at a mutually agreeable location on the customer's property, as close as practicable to the metering point.

903.3 RPU Owned Material – RPU will install, own, operate, and maintain the primary underground cable, the distribution transformer, and the secondary connections at the distribution transformer.

903.4 Conduit Required (RPU Underground Facilities) – If underground primary distribution facilities are located on the customer's property, the customer or their electrical contractor shall provide the conduit from a designated point of interconnection to the distribution transformer.

903.5 Conduit Required (RPU Overhead Facilities) – If overhead main distribution facilities are located on or adjacent to the customer's property, the customer shall provide conduit from the riser pole, including the long sweep elbows, to the pad-mounted distribution transformer. Refer to Section 1200, Exhibit 8 for details.

903.6 Concrete Transformer Pad – The customer shall install, own and maintain a concrete transformer pad constructed to RPU specifications.

(1) If the transformer is located in an area subject to physical damage (e.g. from vehicular traffic), RPU will require the customer to furnish and install an approved means of protection (such as bollards)

(2) The customer will be required to construct or position the concrete transformer pad in such a way to avoid other types of transformer damage, such as corrosion resulting from snow-melt chemicals

903.7 Customer Owned Material – The customer shall install, own, and maintain all secondary cables, conduits, and cabinets from the transformer or secondary pedestal to the building service entrance.

(1) Secondary Bus Duct – RPU must approve the design of all secondary bus duct and cable bus designs. The installation may be inspected by RPU and the secondary connections to the transformer and the transformer side of the connection cabinet will be made by RPU

(2) Customer Coordination – It is the customer's responsibility to coordinate with and provide the necessary information to RPU to assure that adequate connections are made at the secondary terminals of the transformer

903.8 Metering – RPU will furnish and install the meter set in accordance with the requirements of Section 600.

903.9 Maximum Secondary Connections – The maximum number of secondary connections available shall be:

(1) <u>Single Phase</u>: Six (6) 350 MCM conductors per phase

(2) <u>Three Phase</u>:

TRANSFORMER SIZE	# OF CONDUCTORS PER PHASE
45 KVA	3
75 KVA to 500kVA	6
750kVA to 2500kVA	10

(3) The maximum size secondary conductor to be installed in a 3-phase transformer is 500 MCM. Conductors may be aluminum or copper and parallel conductors shall be of identical wire size

<u>Exception</u>: Where the customer's NEC ® service ampacity requirement (as determined by others) exceeds the maximum allowable cable quantity shown above for 500 MCM copper conductors at 90°C temperature rating, contact RPU's Engineering Department for assistance.

(4) Any service requiring more conductors per phase than listed above <u>must</u> utilize a customer provided secondary connection cabinet complying with the requirements of Section 904

903.10 Manhole Secondary Connections – Secondary cables installed in an RPU manhole must be copper conductor.

904 SECONDARY CONNECTION CABINETS

904.1 General – Where secondary connection cabinets are necessary, the following requirements apply:

(1) Cabinet assemblies will be suitable for the installation and comply with all RPU and National Electric Code® requirements

(2) Cabinets shall be constructed with provisions for bar-type or donut-type current transformers

(3) Conduits from service equipment to the connection cabinet and from the transformer to connection cabinet will be furnished and installed by electrical contractor as concrete pads are being formed and poured. Conduit systems shall meet RPU requirements. Above-grade raceway from the transformer to the connection cabinet is not allowed.

904.2 Clearance Requirements – Secondary connection cabinets must be installed such that the minimum clearance requirements for pad-mounted transformers specified in Section 1200, Exhibit 7 are maintained.

904.3 Inspections – During the required transformer pad inspection, if the secondary connection cabinet is found to be in violation of the minimum required pad-mount transformer clearances, the inspection will be marked as 'FAILED'. The contractor will need to correct the observed deficiencies and submit a new form for inspection.

905 TRANSFORMER CLEARANCES

Where pad-mounted transformers are installed, the minimum clearances specified and shown in Section 1200, Exhibit 7 must be maintained. Fences, shrubbery, manholes, junction boxes, and trees may be installed by the customer if the specified clearances are maintained, grade is not altered, and the underground cable is not endangered.

906 OTHER PAD-MOUNTED EQUIPMENT CLEARANCES

Where pad-mounted equipment such as capacitor banks, switchgear, or primary metering cabinets are installed, the following minimum clearances shall be provided:

(1) Ten (10) feet in front of the access doors

(2) Three (3) feet from the sides and/or back of the equipment

The above minimum clearances must be at the same grade as the equipment.

907 WINTER INSTALLATION

The customer shall be required to pay a per foot additional fee for underground cable installation, at the customer's request, after frost has been established in the ground to an average depth of 6 inches or more. The amount of the frost fee depends on the depth of the frost. RPU may require that the estimated frost charges be paid in advance of performing work.

908 INSTALLATION IN UNSUITABLE SOILS

The customer shall be required to pay an additional fee if unsuitable backfill material is encountered during the installation of RPU's facilities. The fee will be based on the cubic feet of unsuitable backfill material encountered by RPU or our contractor during installation. RPU may require that the customer pay an estimated fee prior to performing the work.

909 TOTAL UNDERGROUNDING

RPU does not install underground vaults, manholes, or submersible transformers on customer property. If the presence of permanent structures up to the property lines, or other conditions, precludes the installation of pad-mounted equipment on the customer's property, primary service will normally be provided.

SECTION 1000 – TRANSFORMERS AND TRANSFORMER DATA

1001 TRANSFORMERS

1001.1 Ownership – Necessary transformers will be installed and maintained by RPU in accordance with its established Rate Schedules and Electric Service Rules and Regulations.

1001.2 Requirements – RPU will not furnish transformers unless they are of standard size and voltage as established by RPU. The customer shall notify RPU in advance of any change in the customer's load requirements that may affect the installed transformer capacity.

1002 GROUNDING

1002.1 Grounded System – All service systems that operate below 600 volts contain a grounded neutral or a grounded phase conductor used as a circuit conductor in the system. The grounded neutral or grounded phase conductor is grounded at the supply transformer and will be run from the transformer bank to the meter socket and to each service disconnection means in accordance with National Electric Code® Article 250.24(B), or as may be amended.

1002.2 Ungrounded System – Customers requiring an ungrounded service for operation of a ground detection system, or for other operations permitted by the National Electric Safety Code®, shall submit an exception request detailing the special circumstances necessitating the request. In addition, the customer shall state in the exception request that he is aware of and accepts the increased risk to personal safety associated with an ungrounded service. When supplying an ungrounded service results in an additional cost to RPU, the additional cost may be passed on to the customer.

1003 SPECIAL RULES

1003.1 Customer Furnished Equipment – When a customer is furnished primary service by RPU and installs transformers or other equipment, in accordance with the applicable RPU rate schedule and Electric Service Rules & Regulations, RPU accepts no responsibility for maintaining or replacing the customer's transformers or other equipment if damaged or destroyed.

1003.2 Required Clearances – The customer shall provide a minimum of ten (10) feet of level clearance on the door side(s) of pad-mounted transformers for hot-stick operation and ten (10) feet level clearance on the door side(s) of pad-mounted primary metering cabinets for instrument transformer maintenance. Additional clearance requirements are located in Section 1200, Exhibit 7.

1004 FAULT CURRENT

1004.1 Intention – It is RPU's intent to address the customer's need for information concerning fault current and transformer protective device requirements pertaining to new construction, rewiring, or additional load. Refer to the current edition of the National Electric Code®, Article 110.9 Interrupting Rating and Article 110.16 Arc Flash Hazard Warning, or as may be amended.

1004.2 Tables – Tables 10.1 through 10.3 in this Section show the maximum available RMS symmetrical fault current that may be expected at the secondary terminals of distribution transformers. Each fault current value listed in the tables is based on the percent impedance value of the transformer that might be set initially or as a replacement. No primary source or secondary line impedance has been included since it is generally relatively small, may change, and cannot be accurately forecasted.

Note: Because an overloaded transformer is typically replaced with the next larger standard size transformer, and an under-loaded transformer may be replaced with the next smaller standard size transformer, the customer shall use this range of transformers to perform their analysis and select equipment such as fuse or circuit breakers and service entrance bus bar bracing. When selecting the fault current interrupting rating of the customer protection devices, the customer should also take into account the minimum size transformer that would be required to serve the load rating of the customer main protection device.

1004.3 Variability – Due to the variability of the transformer and electric distribution system characteristics, these tables should be used as a general guideline and shall not be used as a design tool to replace engineering that may be required by the Code Authorities having jurisdiction. Customers or contractors requiring specific fault current calculations should consult a registered professional engineer of their choice.

Note 1: All installations served from a single-phase pad-mount transformer should as a minimum use the calculations based on the installation of a 37.5 kVA transformer.

Note 2: All temporary construction meter installations may use the actual transformer size.

1005 ARC FLASH

1005.1 Intention – It is RPU's intent to address the customer's need for information concerning arc flash data requests as follows:

(1) For secondary voltage services, RPU will provide upon request from the customer:

a) Transformer size, primary voltage, secondary voltage and typical transformer percent impedance

b) Transformer primary fuse information and size type

c) Calculated symmetrical bolted three-phase fault current, bolted single-line ground fault current, and calculated system impedance (R and X) at the high side of the transformer

d) The upstream protective device information nearest the service point. This information will include the device model, rating and applicable settings

(2) For primary voltage services, RPU will provide upon request from the customer:

(3) Calculated symmetrical bolted three-phase fault current, bolted single-line ground fault current and calculated system impedance (R and X) at the service point

(4) The upstream protective device information nearest the service point. This information will include the device model, rating and applicable settings

1005.2 Calculations – Fault current calculations are based upon the distribution system configuration at the time of the calculations. RPU does not provide minimum fault current information or associated protective device clearing times.

1005.3 Use of Data – It is understood that this data is to be used for arc flash calculations. Parties using this data must understand that it may change due to various reasons. RPU will not notify the customer when such changes occur.

1005.4 Table Data – Tables 10.1 through 10.3 in this Section are only intended to provide the basic information necessary for secondary service customers to make their own internal system fault current and basic arc flash calculations. Primary service customers will still need to consult with RPU's Engineering Department to obtain fault current and protective device information for their service locations.

Note: As a safety measure, RPU recommends that when customers are performing maintenance work on or near exposed electrical equipment that their electrical system be de-energized whenever possible.

Table 10.1 Single Phase Underground

SINGLE-PHASE PADMOUNT TRANSFORMERS EXPECTED SINGLE-PHASE FAULT CURRENTS (IN RMS AMPS) AT THE SECONDARY TERMINALS						
					PROTECTIVE DEVICE, OVERHEAD FUSE	
TRAN	TRAN	TRAN	TRAN	Fault Current	**7960V PRIMARY**	
KVA	%Z	%R	%X	240V Secondary	BAY-O-NET	Amps
5	1.00	0.39	0.92	2,085	4000358C05	8
15	1.00	0.39	0.92	6,250	4000358C05	8
25	1.00	0.32	0.95	10,420	4000358C08	15
37.5	1.00	0.25	0.97	15,630	4000358C08	15
50	1.10	0.57	0.94	18,940	4000358C08	15
75	1.10	0.38	1.03	28,410	4000358C10	25
100	1.10	0.34	1.05	37,880	4000358C10	25
167	1.20	0.34	1.05	57,990	4000358C12	50
					PROTECTIVE DEVICE, OVERHEAD FUSE	
TRAN	TRAN	TRAN	TRAN	Fault Current	**7960V PRIMARY**	
KVA	%Z	%R	%X	480V Secondary	BAY-O-NET	Amps
15	1.1	0.39	1.03	2,840	4000358C05	8
Note: BAY-O-NET fuse is a COOPER/EATON or equivalent						

Table 10.2 Single Phase Overhead

SINGLE-PHASE OVERHEAD TRANSFORMERS EXPECTED SINGLE-PHASE FAULT CURRENTS (IN RMS AMPS) AT THE SECONDARY TERMINALS										
									PROTECTIVE DEVICE, OVERHEAD FUSE	
TRAN	TRAN	TRAN	TRAN	Fault Current	TRAN	TRAN	TRAN	Fault Current	**7960V PRIMARY**	
KVA	%Z	%R	%X	240V Secondary	%Z	%R	%X	120V Secondary	Typical	Limited Use
10	1.20	0.35	1.15	3,470	1.48	0.53	1.38	5,630	1.5X	6 ELF
15	1.20	0.66	1.00	5,210	1.56	0.99	1.20	8,010	2X	6 ELF
25	1.20	0.50	1.09	8,680	1.51	0.75	1.31	13,800	3.5X	6 ELF
37.5	1.20	0.39	1.13	13,020	1.48	0.59	1.36	21,110	5.5X	8 ELF
50	1.20	0.43	1.12	17,360	1.49	0.65	1.34	27,960	7X	12 ELF
75	1.20	0.17	1.19	26,040	1.45	0.26	1.43	43,100	10X	18 ELF
167	1.20	0.17	1.19	57,990	1.45	0.26	1.43	95,980	25KS	18 ELF

Table 10.3: Three Phase Pad-mount Transformers

THREE-PHASE PADMOUNT TRANSFORMERS EXPECTED THREE-PHASE FAULT CURRENTS (IN RMS AMPS) AT THE SECONDARY TERMINALS									
						TRANSFORMER PROTECTIVE DATA			
TRAN KVA	TRAN %Z	TRAN %R	TRAN %X	Fault Current 120/208V Secondary	Fault Current 277/480V Secondary	Current Limiting Cooper/Eaton or Equivalent	Size Amps	BAY-O-NET Cooper/Eaton or Equivalent	Size Amps
45	1.3	1.04	0.78	9,600	N/A	CBUC08030C100	30	4000358C05	8
75	1.3	0.7	1.10	16,000	6,900	CBUC08080C100	80	4000358C08	15
112.5	1.4	0.49	1.31	22,300	9,700	CBUC08080C100	80	4000358C08	15
150	1.4	0.35	1.36	29,700	12,900	CBUC08080C100	80	4000358C08	15
225	1.4	0.43	1.33	44,600	19,300	CBUC08100C100	100	4000358C10	25
300	1.4	0.48	1.32	59,500	25,800	CBUC08125C100	125	4000358C10	25
500	1.6	0.40	1.55	86,700	37,600	CBUC08150D100	150	4000358C12	50
750	4.5	0.39	4.48	46,300	20,000	CBUC08250D100	250	4000358C14	65
1,000	5.1	0.32	5.09	54,400	23,600	CBUC08150D100	150	4038361C03CB	135
1,500	5.1	0.36	5.09	N/A	35,400	CBUC08150D100	150	4038361C03CB	135
2,000	5.1	0.43	5.08	N/A	47,200	CBUC08165D100	165	4038361C04CB	165
2,500	5.1	0.33	5.09	N/A	59,000	CBUC08250D100	250	4038361C05CB	185

SECTION 1100 – SUPPLEMENTAL INFORMATION

1101 USE OF SERVICE

1101.1 Purpose – Electric service may be used only for the purposes set forth in the respective rate schedules. RPU is in the business of providing retail electricity to the ultimate consumer. Electricity is supplied for use by customer's household or business, and outside sale of such service is not permitted. RPU permits redistribution and sub-metering where allowed by law, but a landlord may not charge the tenants more than the landlord is charged by RPU.

1101.2 Arrangement – The electric service equipment and associated building wiring of buildings must be arranged by the owner to facilitate individual metering of the electrical consumption of each building and occupancy unit. (Minnesota Statute Section 326B.106 Subd.12 requires separate metering on most residential units). If desired by the owner, RPU will install and maintain necessary individual RPU meters to measure consumption and tender bills on the applicable rate schedules to each customer and separately occupied buildings and occupancy units. Installation and maintenance of individual RPU meters by RPU shall not relieve the owner or landlord of responsibility for electrical service equipment and associated building wiring, nor shall it relieve the owner or landlord of responsibility to notify RPU of a single-metered residential building.

1101.3 Metering – Electric service in a single-metered residential building, as defined pursuant to Minn. Stat. 504B.215, shall be billed to the landlord/building owner except when a de minimis exception exists. A de minimis exception to the determination that a building is a single-metered residential building exists if electrical service used in a common area but measured by an individual tenant's meter does not exceed an aggregate 1,752 kilowatt hours per year. The landlord shall bear the burden and cost associated with proving an exception. (Minnesota Statute 504B.215 Subd. 2 requires the landlord of a single-metered residential building shall be the bill payer responsible, and shall be the customer of record contracting with the utility, and requires the landlord to advise the utility of the existence of a single-metered residential building). Except where a de minimis exception applies, a single metered residential building includes the following situations: "shared meter" in which a utility meter measures service provided to a tenant's dwelling and also measures such service to areas outside that dwelling; or "mixed wiring" in which electric outlets, fixtures or devices outside the individual unit are included on an individual meter; or "mixed plumbing" when related to electric utility service such as when an electric water heater serves more than one individual unit. RPU shall respond to a tenant customer's request for a shared meter investigation within ten (10) business days. RPU's investigation shall consider whether a de minimis exception applies.

1101.4 De Minimis – The following may be representative de minimis exception examples:

(1) Common area lighting fixtures up to two (2) 100-watt light bulbs operating 24 hours/day, seven days per week
(2) Common area outlets without constant motor loads, such as an outlet in a hallway used for housekeeping
(3) Common area garage door opener for non-commercial use.
(4) Mixed wiring with another tenant unit
(5) Laundry appliances accessible by multiple tenants
(6) Common area lighting fixtures exceeding two (2) 100-watt light bulbs operating 24 hours/day, seven days per week usage

A landlord seeking to prove a de minimis exception shall do so by providing evidence establishing by actual measurement that the usage does not exceed 1,752 kilowatt hours per year. Where such actual measurement is not possible the landlord shall present written documentation from a licensed tradesperson or housing inspector that this usage is not likely to exceed 1,752 kilowatt hours per year. Such evidence must be presented prior to, during, or within 30 days of the conclusion of a shared meter investigation.

1101.5 Adjustments – Upon discovery of a single-metered residential building, as defined pursuant to Minnesota. Statute Section 504B.215, whether shared metering, mixed wiring or mixed plumbing in which individual metered service had been established and billed, RPU shall, within thirty (30) business days, recognize and make adjustments to its records to reflect that the landlord/building owner is the bill payer responsible and customer of record. RPU shall make adjustments to the tenants and landlord/building owners account based on Minnesota State Statute and RPUs standard practices. Additionally, the tenant or landlord/building owner may seek additional adjustment of charges or challenge RPU's finding of a shared meter situation by filing a complaint with the Minnesota Public Utilities Commission, or by court action. Upon request, RPU will provide to the tenant available billing history in relation to such additional actions. The Minnesota Public Utilities Commission has determined that regardless of how or by whom an investigation is initiated leading to utility account adjustments, credits and/or refunds as herein described, the investigation and any resulting adjustments, credits and/or refunds shall implicate the protections of Minnesota Statute Sections 504B.285 Subds. 2 and 3, and 504B.441.

In the event the landlord/building owner denies access to the building or fails to cooperate with an investigation to determine whether a single-metered residential building exists, as defined pursuant to Minnesota Statute Section

504B.215, the building shall be presumed to be a single-metered residential building as defined pursuant to Minnesota Statute Section 504B.215, and the landlord/building owner shall be the bill payer responsible and customer of record. RPU shall make adjustments to the tenants and landlord/building owners account based on Minnesota State Statute and RPU's standard practices. Additionally, the tenant or landlord/building owner may seek additional adjustment of charges or challenge RPU's finding of a shared meter situation by filing a complaint with the Minnesota Public Utilities Commission, or by court action. The Minnesota Public Utilities Commission has determined that regardless of how or by whom an investigation is initiated leading to utility account adjustments, credits and/or refunds as herein described, the investigation and any resulting adjustments, credits and/or refunds shall implicate the protections of Minnesota Statute Sections 504B.285 subds.2 and 3, and 504B.441.

1101.6 Service Re-establishment – In order to reestablish individual metered service for the individual tenant units, the landlord/building owner shall be required to provide certification of a licensed electrician that the building has been inspected sufficiently to determine that all instances of mixed wiring, shared metering and mixed plumbing have been eliminated or that the building qualifies for a de minimis exception, as shown by actual measurement or by certification by a licensed tradesperson or housing inspector. Additionally, the building owner may be required by RPU to post a deposit equal to the expected charges for up to two months of usage for electric service to the building.

RPU shall have the right to verify the certification at the landlord/building owner's expense prior to establishing metered service for individual units. Such verification shall not relieve the landlord/building owner of its responsibility to be the bill payer and customer of record of a single-metered residential building as defined pursuant to Minnesota Statute Section 504B.215.

1101.7 MN PUC Petition – In the event of discovery of a single-metered residential service, as defined pursuant to Minnesota Statute Section 504B.215, after previous certification to reestablish individual metered service for tenants, in addition to the above adjustments, the building shall be ineligible for individual metered service for tenants without petition to the Minnesota Public Utilities Commission by the landlord/building owner and a showing by the building owner by clear and convincing evidence justifying the reestablishment of individual metered service for tenants. Additionally, the MPUC may require consent of the building's tenants in determining that reestablishment of the individual metered service for tenants is appropriate.

1101.8 Series Metering – RPU will not install, operate, maintain, or acquire any series metering system. RPU may, however, require series subtractive metering for its own purposes to measure consumption and render bills for electric energy not otherwise measured.

1101.9 Service Arrangement – Electricity is normally supplied to each separate customer through a single service and meter. RPU does not engage in the practice of doing interior wiring on customer's premises except for the installation and maintenance of its own property. The customer may combine the supply of electricity through one meter and one service to two or more buildings or occupancy units if they are located on the same or contiguous parcels of property and occupied by the same customer, solely for customer's own use. If separate buildings are occupied in whole or part by tenants of the customer, then each tenant occupied building, or area, or occupancy unit must be segregated from other loads of the customer and metered by RPU.

1101.10 Legacy Arrangement – If more than one building with tenants, or portions of more than one building with tenants, are served through one meter, this practice may continue until such time as material structural changes are made that will result in major modifications to the customer's service entrance equipment. If such modifications do occur, provisions must be made to allow for individual RPU metering of each tenant occupied building, or area, or occupancy unit. While the single meter service continues, the bill for the buildings will be computed as though each building used an equal portion of the total metered service and was separately billed.

1101.11 Customer Responsibility – All wiring and equipment on customer's side of the point of delivery, except metering equipment, will be furnished, installed, and maintained at the customer's expense in a manner approved by the public authorities having jurisdiction over the same. Customer will protect all electrical equipment and systems with devices that conform to the industry accepted standard for the various classes of electrical equipment and systems to prevent fire or damage to equipment from electrical disturbances or fault occurring in the customer's system or in the supplying system. The "industry accepted standard" will be as required in the National Electrical Code and such additional devices as are prescribed by any public authority with jurisdiction over the installation of electrical facilities.

1101.12 Inspections – Any inspection of a customer's wiring and equipment by RPU is for the purpose of avoiding unnecessary interruptions of service to its customers or damage to its property, and for no other purpose, and will not be construed to impose any liability upon RPU to a customer or any other person by reason thereof. In addition, RPU will not be liable or responsible for any loss, injury, or damage that may result from the use of or defects in a customer's wiring or equipment.

RPU may, however, at any time require a customer to make such changes in customer's electrical or non-electrical property or use thereof as may be necessary to eliminate any hazardous condition or any adverse effect which the operation of the customer's property or equipment may have on said customer, other customers of RPU, the public, or RPU's employees, equipment or service. In lieu of changes by the customer, RPU may require reimbursement from the customer for the cost incurred by RPU in alleviating an adverse effect on RPU's facilities caused by the customer's property.

1101.13 Capacity – The transformers, service conductors, meters, and appurtenances used in furnishing electric service to a customer have a definite capacity. Therefore, no material increase in load or equipment will be made without first making arrangements with RPU for the additional electric supply.

1102 RATE SCHEDULE CLASSIFICATION

Electric service is supplied to customers under various rate schedule classifications as determined by the type of service, the amount of electric power supplied, and the purpose for which the electric service is to be used. Copies of RPU's rate schedules are available at RPU's Service Center and https://www.rpu.org/my-account/rates-fees.php.

1103 PAYMENT

1103.1 Meter Reading – RPU will, insofar as possible, read all meters every month and bill the customer for service used during the period. Payment of the bill is due by the date noted on the bill.

1103.2 Estimated Billing – If the meter cannot be read during a billing period, or the reading seems erroneous, an estimate will be made for that billing period. Adjustments to bills resulting from inaccuracies in the meters will be handled in the manner described in Section 608, Meter Testing.

1104 CUSTOMER CHARGE

There is a customer charge for each meter/service provided. The amount of this customer charge will vary based on the type and number of services provided (refer to RPU's rate schedule(s) for more information).

1105 NEW UNDERGROUND RESIDENTIAL SERVICE CONNECTION CHARGE

1105.1 Charges – RPU will charge an underground service connection charge (New Underground Service fee) for the extension and/or connection of new underground electrical service to any single-family home, townhome, condominium, duplex or triplex located in a R-1, R-1x, R-Sa, R-2, R-4 or Special District, zoning districts. The amount of the charge can be obtained from a Customer Care Advisor.

1105.2 Service Connections – There will be no charge for connections or reconnections of existing services, in good payment standing, during RPU's normal working hours. If connection must be made outside of normal working hours at the request of the customer, a special connection charge will be assessed. The charge for such work can be obtained from a Customer Care Advisor.

1106 SERVICE DISCONNECTION/RECONNECTION

1106.1 With Notice – RPU may disconnect a customer's service, with notice, for any of the following reasons:

(1) Nonpayment of billings or issuance of non-negotiable check
(2) Nonpayment of a deposit or other charges/fees
(3) Failure to meet credit requirements
(4) Failure to provide access to RPU owned metering equipment

1106.2 Without Notice – RPU may disconnect a customer's service, without notice, for any of the following reasons:

(1) A condition determined to be hazardous – to the customer, to other customers, or to RPU personnel
(2) Unauthorized use of electricity, water, or equipment belonging to RPU

1106.3 Reconnection Fee – In the event service has been disconnected for nonpayment, deposit, theft, or other credit cause, the customer will be required to pay a reconnection fee before the service is restored. In the event that the service is disconnected because of hazardous conditions on the customer owned equipment or unauthorized use, the customer will be required to have all required inspections performed prior to service being restored.

1106.4 Fee Schedule – A schedule of fees is available from an RPU Customer Care Advisor.

1107 SERVICE DEPOSIT

RPU has established a credit policy whereby existing customers with an acceptable credit history and customers never having had service with RPU may not be required to provide a deposit as a condition of service. A new or additional deposit may be required in cases where a deposit has been refunded or where the current deposit amount is inadequate. The deposit amount is based on two times the average monthly bill and bears interest at the rate established by Minnesota Statute Section 325E.02. Further information is available in the RPU Deposit Policy.

1108 SECURITY LIGHTING

Security lighting is available under its own rate schedule classification for those customers requesting it.

1109 POWER FACTOR CORRECTION CALCULATION

Refer to Table 11.1 on the following page for instructions for multipliers to determine required capacitor kVARs for correcting power factor

TABLE 11.1 – POWER FACTOR CORRECTION CALCULATION TABLE

ORIGINAL POWER FACTOR	CORRECTED POWER FACTOR						
	90%	92%	94%	95%	96%	98%	100%
60%	0.849	0.907	0.970	1.005	1.042	1.130	1.333
62%	0.781	0.839	0.903	0.937	0.974	1.062	1.265
64%	0.716	0.775	0.838	0.872	0.909	0.998	1.201
66%	0.654	0.712	0.775	0.81	0.847	0.935	1.138
68%	0.594	0.652	0.715	0.750	0.787	0.875	1.078
70%	0.536	0.594	0.657	0.692	0.729	0.817	1.020
72%	0.480	0.538	0.601	0.635	0.672	0.761	0.964
74%	0.425	0.483	0.546	0.580	0.617	0.706	0.909
76%	0.371	0.429	0.492	0.526	0.563	0.652	0.855
78%	0.318	0.376	0.439	0.474	0.511	0.599	0.802
80%	0.266	0.324	0.387	0.421	0.458	0.547	0.750
82%	0.214	0.272	0.335	0.369	0.406	0.495	0.698
84%	0.162	0.220	0.283	0.317	0.354	0.443	0.646
86%	0.109	0.167	0.230	0.265	0.302	0.390	0.593
88%	0.055	0.114	0.177	0.211	0.248	0.337	0.540
90%	0	0.058	0.121	0.156	0.193	0.281	0.484
92%		0	0.063	0.097	0.134	0.223	0.426
94%			0	0.034	0.071	0.160	0.363
96%					0	0.089	0.292
98%						0	0.203
100%							0

INSTRUCTIONS:

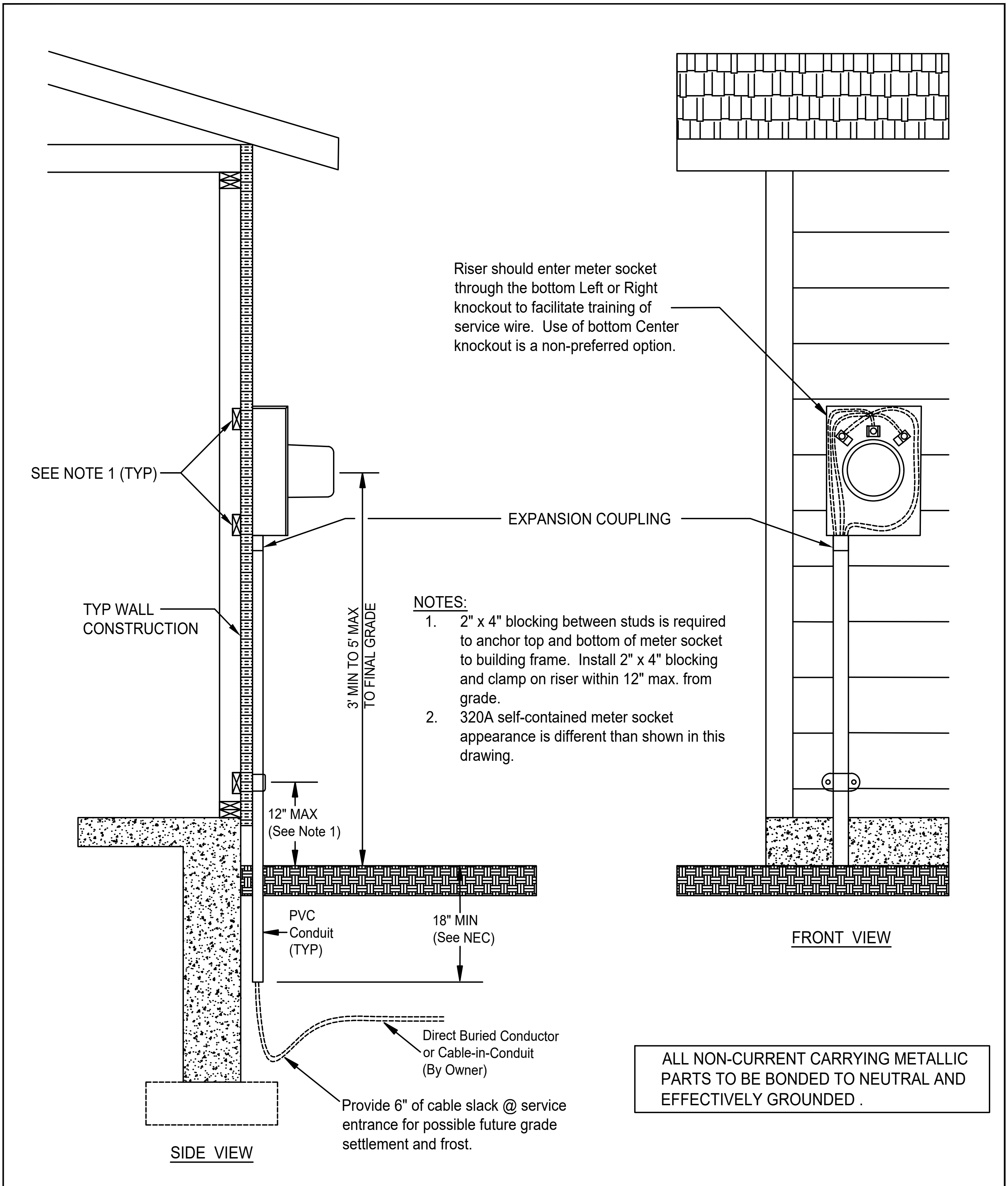
1. Determine the average power factor that your system operates at during peak demand months. Call this your ORIGINAL POWER FACTOR.
2. In the row titled CORRECTED POWER FACTOR at the top of the page, find the power factor that you wish to correct your system to.
3. Read from left to right along the row corresponding to your ORIGINAL POWER FACTOR until you reach the column that shows your desired CORRECTED POWER FACTOR.
4. Read the number that you find at the intersection of the row and column. Multiply your KW Demand by this number to calculate the total amount of capacitor KVAR you need to install to your electric service.
5. If your plant operates with a 3 phase electric service, divide the total KVAR by 3 to determine the amount of KVAR to connect per phase.

Example: If your plant has a 3 phase demand of 410 KW and operates at 76% power factor, but you want to correct to 95%:

a) Find 95% in the CORRECTED POWER FACTOR row at the top of the page
b) Find 76% in the ORIGINAL POWER FACTOR column along the left edge of the page. Read from left to right along this row until you reach the 95% column
c) Read the number at the intersection of the row and column (0.526)
   410 KW x 0.526 = 216 KVAR needed to correct your system to 95% power factor
d) 216 ÷ 3 = 72 KVAR per phase

SECTION 1200 – EXHIBIT DRAWINGS & INFORMATION

EXHIBIT

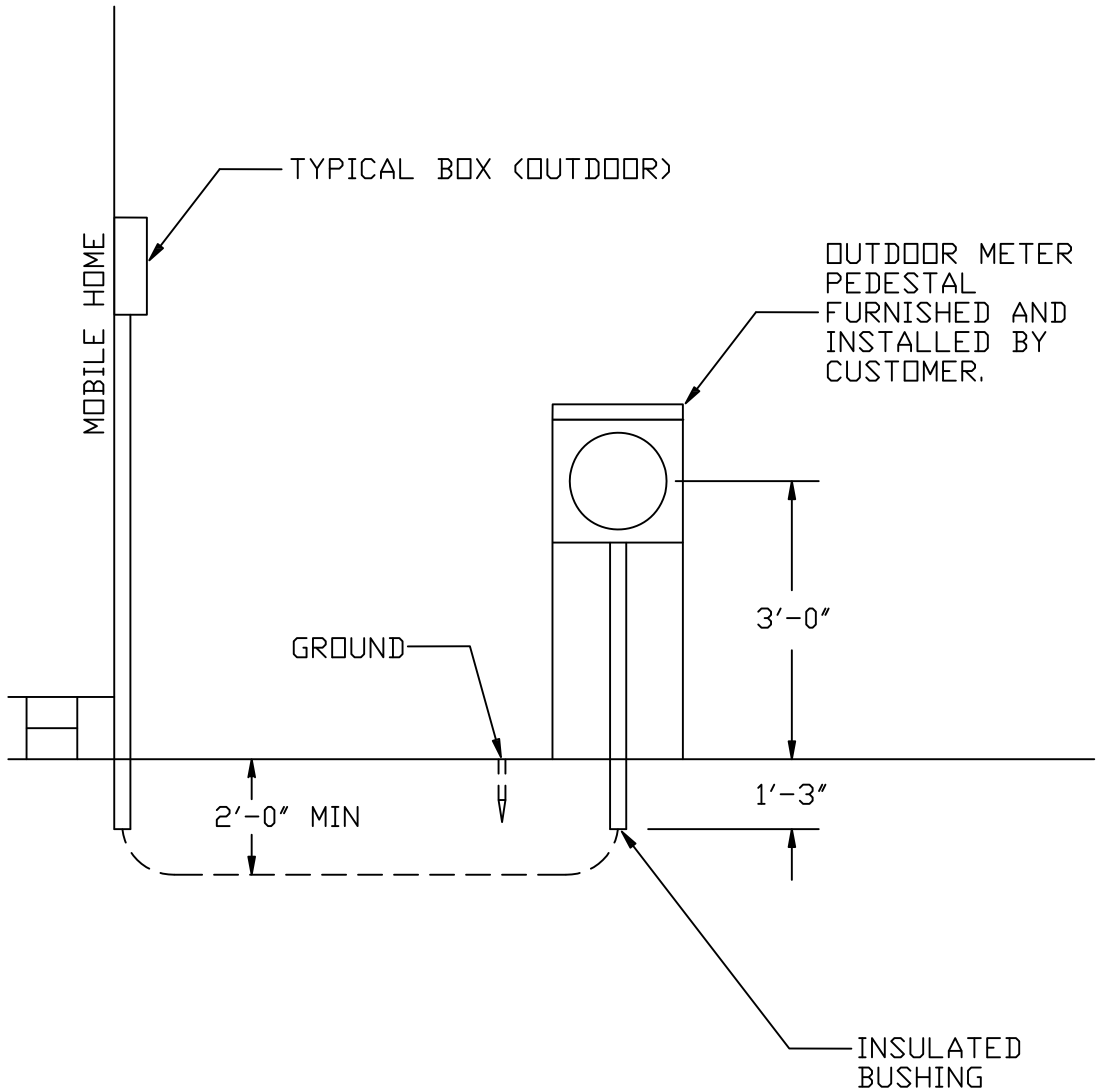


ROCHESTER PUBLIC UTILITIES

NO	REVISION	BY	DATE
0	ORIGINAL DRAWING	BJK	05/01/2017
1	ADJUSTED EXPANSION COUPLING	BJK	02/09/2021

TYPICAL RESIDENTIAL UNDERGROUND SERVICE METER INSTALLATION

EXHIBIT 1



NOTES:

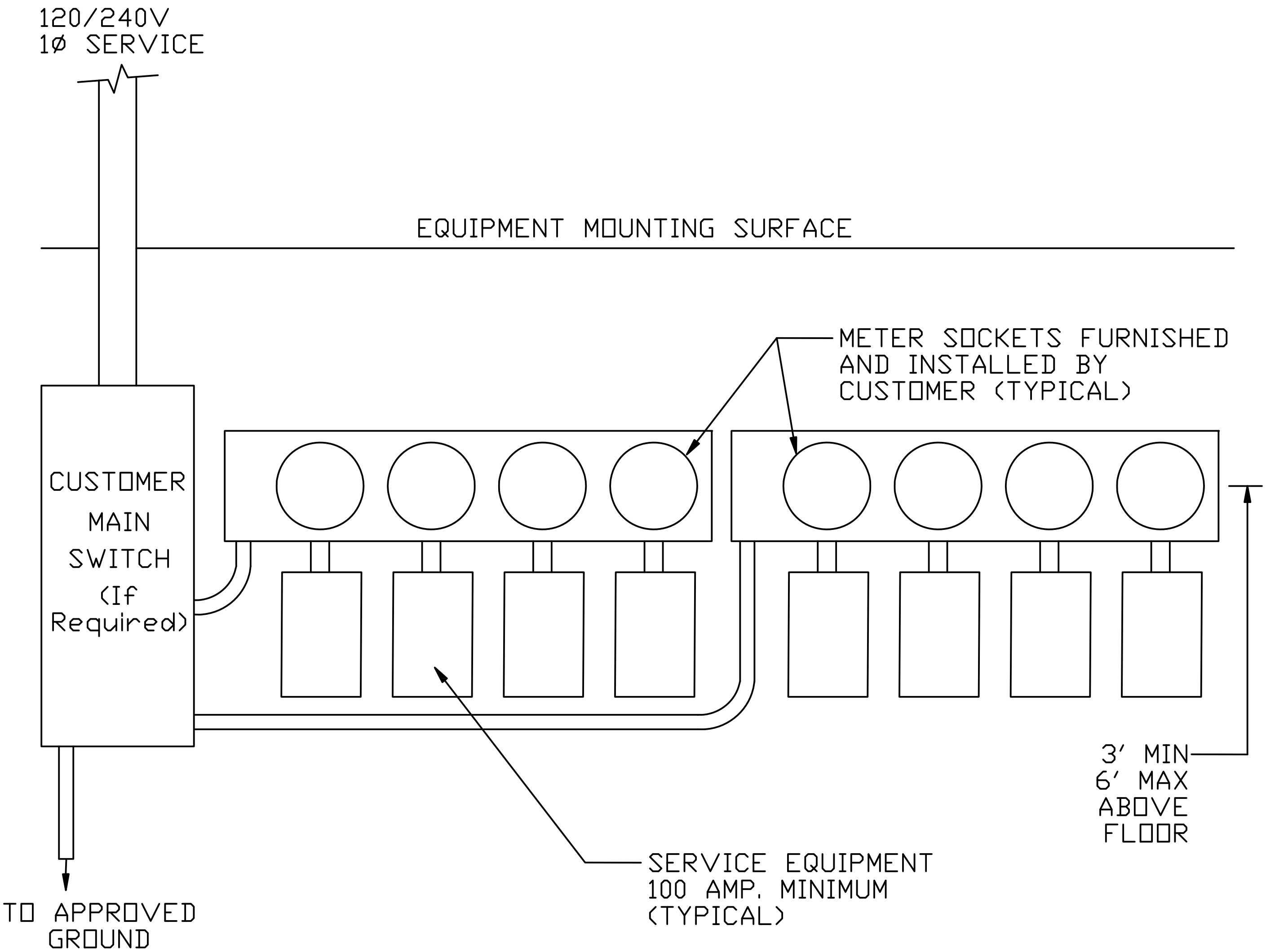
1. All meters shall be permanently labeled.
2. Meters are to face towards street.
3. Service lateral from the secondary junction at the property line, to the meter pedestal, to the mobile home, is the responsibility of the customer.

ROCHESTER PUBLIC UTILITIES

NO	REVISION	BY	DATE
0	ORIGINAL DRAWING	BJK	05/01/2017

TYPICAL MOBILE HOME METERING ARRANGEMENT

EXHIBIT 2



NOTES:

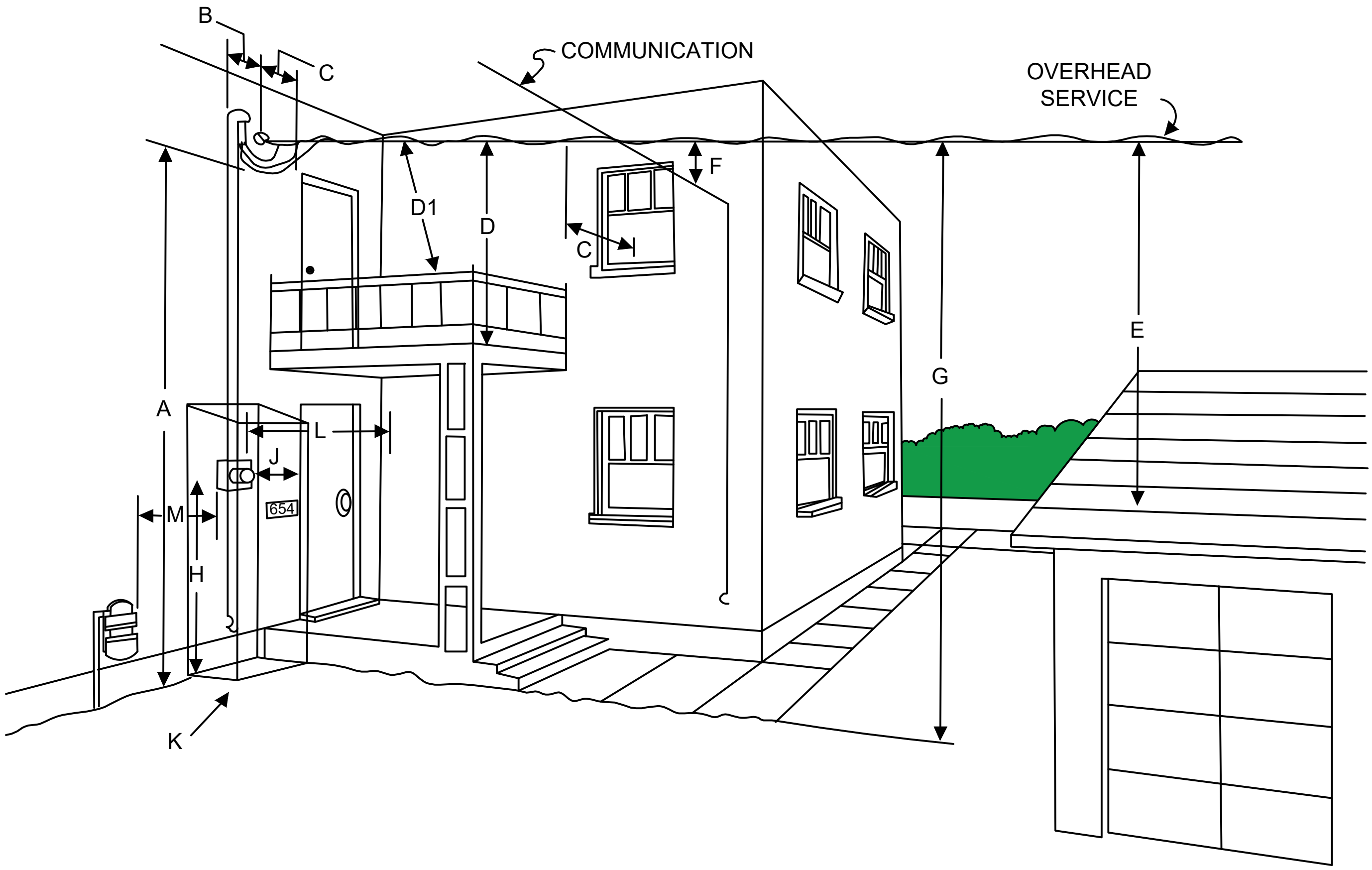
1. All meters shall be permanently labeled.
2. All meters must have individual lock-off capability.
3. All meters must be accessible to RPU personnel and to customers.

ROCHESTER PUBLIC UTILITIES

NO	REVISION	BY	DATE
0	ORIGINAL DRAWING	BJK	05/01/2017

TYPICAL MULTIPLE METERING ARRANGEMENT

EXHIBIT 3



The general clearances listed on the next page, under any and all conditions, include Rochester Public Utilities' requirements and interpretations derived from the NESC Rule 234 and the NEC Section 230.24. Refer to those Sections for specific conditions not depicted. Clearances for utility-owned service drops and cables, beyond the perimeter of the customer's buildings, will be controlled by the NESC requirements. The alphabetical designations and respective dimensions on the next page apply to the illustration above. Clearances shown are for multiplex (duplex, triplex, and quadruplex) service drop conductors only - open wire service conductors require greater clearance.

ROCHESTER PUBLIC UTILITIES

NO	REVISION	BY	DATE
0	ORIGINAL DRAWING	BJK	05/01/2017
1	ADDED CLEARANCE CONDITION D1	BJK	02/08/2021

SERVICE CONDUCTOR CLEARANCES (480V AND BELOW)

EXHIBIT 4

CLEARANCE CONDITION:

A- The drip loop or service attachment fixture, whichever is the lowest point, shall have 12 feet minimum vertical clearance above final grade. Higher clearances may be required, reference "G" below.

B- The clearance between the service attachment and weatherhead shall be 12 inches minimum and 24 inches maximum.

C- Service conductors that are not protected by conduit or raceway shall have a minimum clearance of 3 feet from windows designed to be opened, doors, porches, fire escapes, signs, and similar construction. Conductors run above the top level of a window shall be permitted to be less than the 3 feet requirement.

D- The diagonal distance from the nearest edge of a balcony or deck handrail that is readily accessible to the service conductor shall be 10 feet minimum.

D1- 3.5 feet

E- The minimum vertical clearance shall be:
3.5 feet for roof slope not readily accessible to pedestrians
11.0 feet for roof slope readily accessible to pedestrians

F- Minimum vertical clearances between service drop and communication conductors shall be 2 feet at the conductor crossing and 12 inches at adjacent vertically spaced attachments to the building.

G- The minimum vertical clearance shall be:
12 feet above sidewalk and ground
16 feet above residential driveways
18 feet above commercial areas, public driveways, alleys and streets, and other land traversed by vehicles
20 feet above Department of Transportation right of way and others as required by local jurisdiction

H- For individual settings, the clearance between the center of the meter and the finished grade is to be 5 feet maximum and 3 feet minimum.

J- The dimension between the hinged side of a door and the nearest surface of the meter is to be door width plus 6 inches.

K- A clear working space, as shown by the box in the diagram, of not less than 36 inches in front of the meter and 30 inches wide shall be maintained at all times. (*NEC* Section 110.26)

L- The horizontal clearance from the nearest side of the meter socket enclosure to any structural protrusion shall be 3 inches minimum.

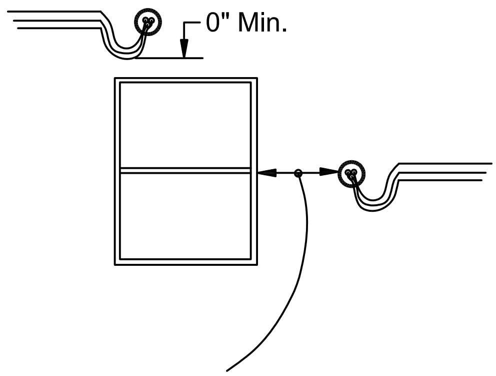
M- Horizontal distance of electric meter to gas regulator vent is 3 feet minimum.

ROCHESTER PUBLIC UTILITIES

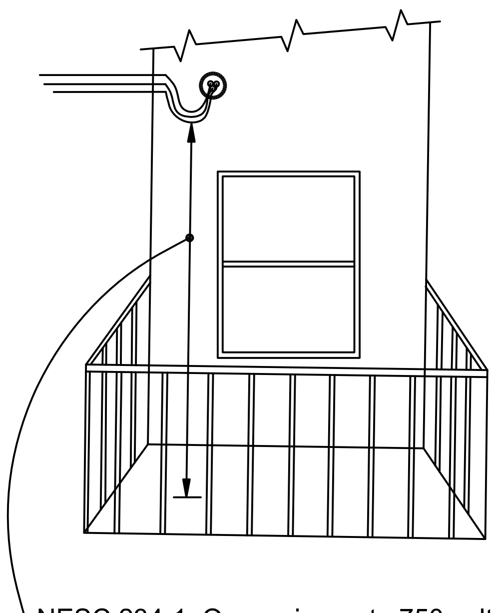
NO	REVISION	BY	DATE
0	ORIGINAL DRAWING	BJK	05/01/2017
1	ADDED CLEARANCE CONDITION D1	BJK	02/08/2021

SERVICE CONDUCTOR CLEARANCES (480V AND BELOW)

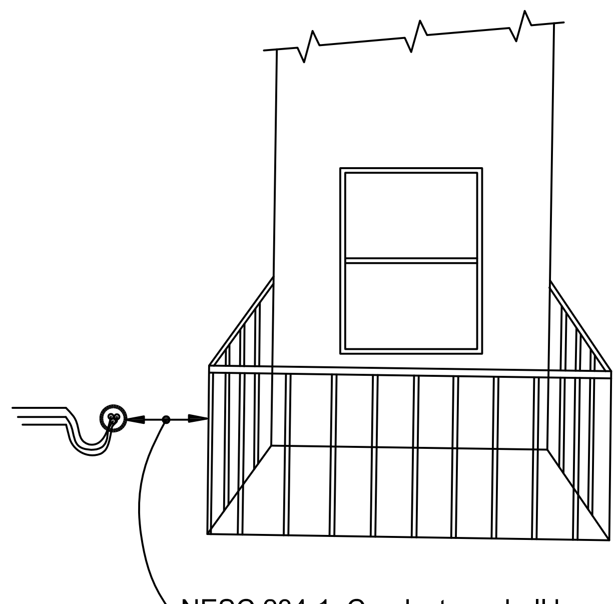
EXHIBIT 4 (Continued)



NESC 234-1: A horizontal clearance of not less than 3' for triplex and 5'-6" for open wire must be maintained from window. Above window a 0" vertical clearance is allowed.



NESC 234-1: Open wire up to 750 volts to ground = 11'-6"
Open wire over 750 volts to ground = 13'-6"
Triplex/quadruplex = 11'-0".



NESC 234-1: Conductors shall have a horizontal clearance of 3' for triplex and 5'-6" for open wire.

ROCHESTER PUBLIC UTILITIES

NO	REVISION	BY	DATE
0	ORIGINAL DRAWING	BJK	05/01/2017

SERVICE CONDUCTOR CLEARANCES FROM WINDOWS AND BALCONIES

EXHIBIT 4.1

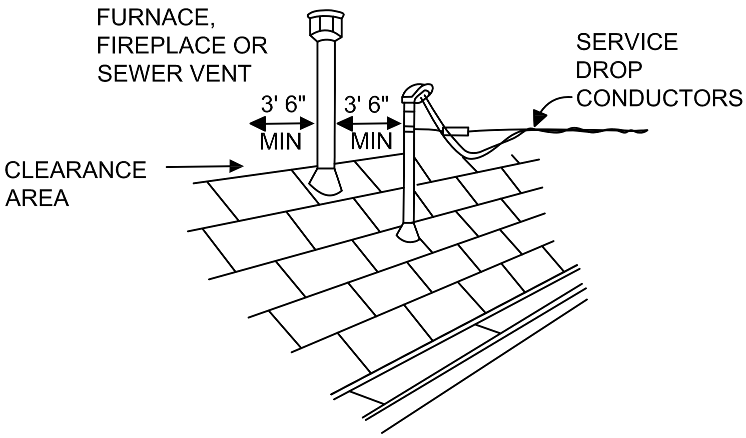


FIG. 1

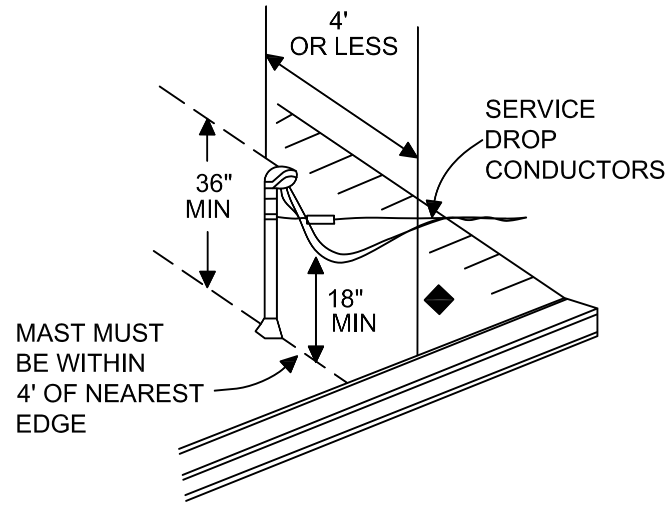


FIG. 2

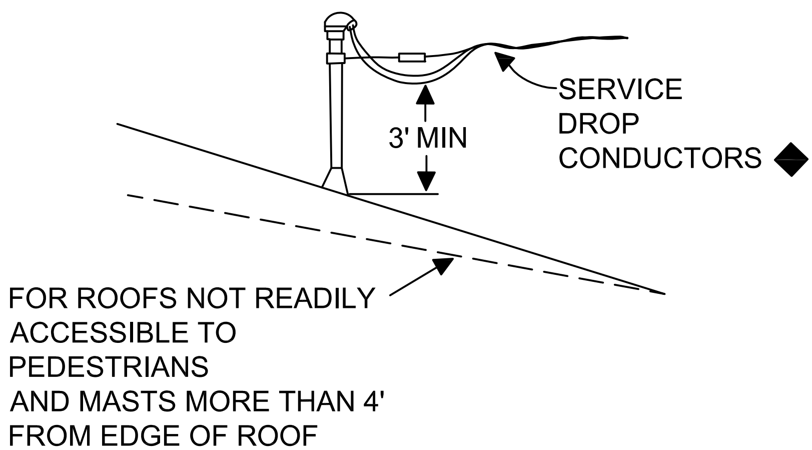


FIG. 3

◆ THIS VERTICAL DIMENSION APPLIES TO ANY POINT ON THE ROOF SURFACE DIRECTLY UNDER THE CONDUCTORS.

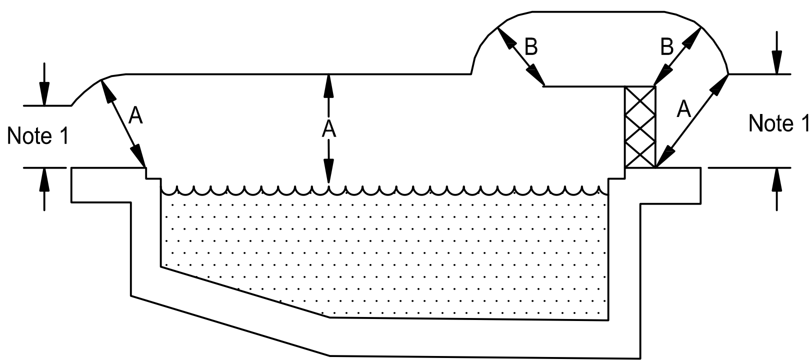
ROCHESTER PUBLIC UTILITIES

NO	REVISION	BY	DATE
0	ORIGINAL DRAWING	BJK	05/01/2017

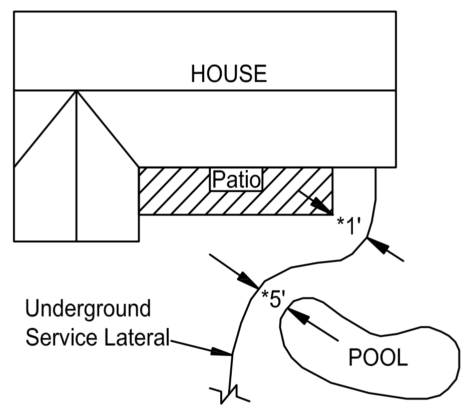
SERVICE CONDUCTOR CLEARANCES OVER ROOFS

EXHIBIT 4.2

Type of Structure Under or Next to Wire	Neutrals, Guys, Messengers; Surge protection; Wires and Communications	Duplex, Triplex, Quadraplex, Lashed 0 - 750 V	Open Supply Conductors 0 - 750 V	Primary Conductors 750 V - 22 kV
Clearance In Any Direction To: Edge of pool, water surface, Base of diving platform or anchored raft. (Dimension A)	22' - 0" (Note 1)	22' - 6" (Note 1)	23' - 0"	25' - 0"
Clearance In Any Direction To: Diving platform or Tower (Dimension B)	14' - 0" (Note 6)	14' - 6" (Note 6)	15' - 0" (Note 6)	17' - 0" (Note 6)
Hot Tubs and Whirlpool Spas: (Notes 4 and 5)	10' - 6"	11' - 0"	11' - 6"	13' - 6"



Clearances of Underground Secondary Service Lateral to Patios and Pools



*These dimensions are minimum unless cable is in conduit

NOTES:

1. 0 - 750 volts except open wire HORIZONTALLY greater than 10 feet from the edge of the pool or diving platform NEEDS ONLY a vertical clearance of 12.5 feet in pedestrian only traffic areas.
2. Table data is for below grade pool (as depicted).
3. Values are from NESC Table 234-3.
4. For hot tubs and whirlpool spas, clearance is the same as clearance from balconies, decks and areas accessible to pedestrians. Clearance would be from the highest point a person could stand to the conductor.
5. For hot tubs and whirlpool spas, clearance is less than swimming pools since long handled cleaning equipment and rescue poles are not used.
6. For horizontal clearance, add 2 feet for conductor swing.

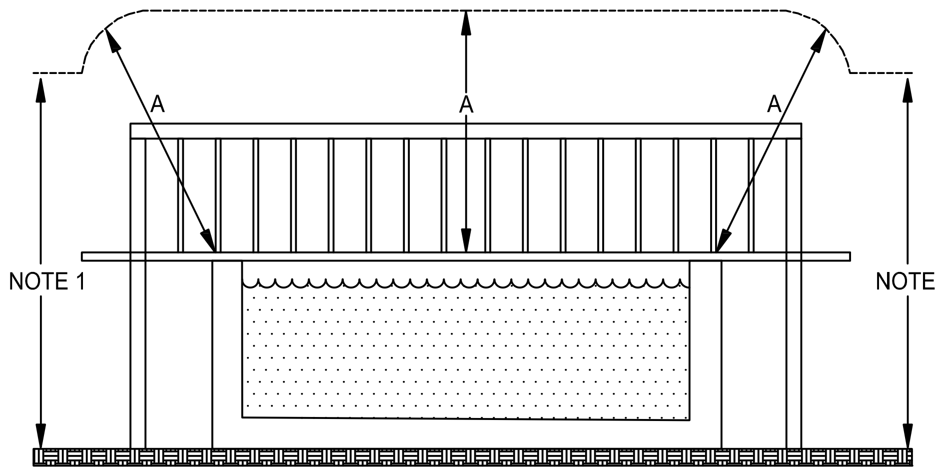
ROCHESTER PUBLIC UTILITIES

NO	REVISION	BY	DATE
0	ORIGINAL DRAWING	BJK	05/01/2017

SERVICE CONDUCTOR CLEARANCES TO PATIOS AND POOLS

EXHIBIT 4.3

Type of Structure Under or Next to Wire	Neutrals, Guys, Messengers; Surge protection; Wires and Communications	Duplex, Triplex, Quadraplex, Lashed 0 - 750 V	Open Supply Conductors 0 - 750 V	Primary Conductors 750 V - 22 kV
Clearance In Any Direction To: Edge of pool, water surface, Base of diving platform or anchored raft. (Dimension A)	22' - 0"	22' - 6"	23' - 0"	25' - 0"
Hot Tubs and Whirlpool Spas: (Notes 2 and 3)	10' - 6"	11' - 0"	11' - 6"	13' - 6"



ABOVEGROUND SWIMMING POOL WITH DECK. CLEARANCE IS MAINTAINED FROM THE HIGHEST POINT OF THE INSTALLATION UPON WHICH PEOPLE CAN STAND.

NOTES:

1. 0 - 750 volts except open wire HORIZONTALLY greater than 10 feet from the edge of the pool NEEDS ONLY a vertical clearance of 12.5 feet in pedestrian only traffic areas.
2. For hot tubs and whirlpool spas, clearance is the same as clearance from balconies, decks and areas accessible to pedestrians. Clearance would be from the highest point a person could stand to the conductor.
3. For hot tubs and whirlpool spas, clearance is less than swimming pools since long handled cleaning equipment and rescue poles are not used.

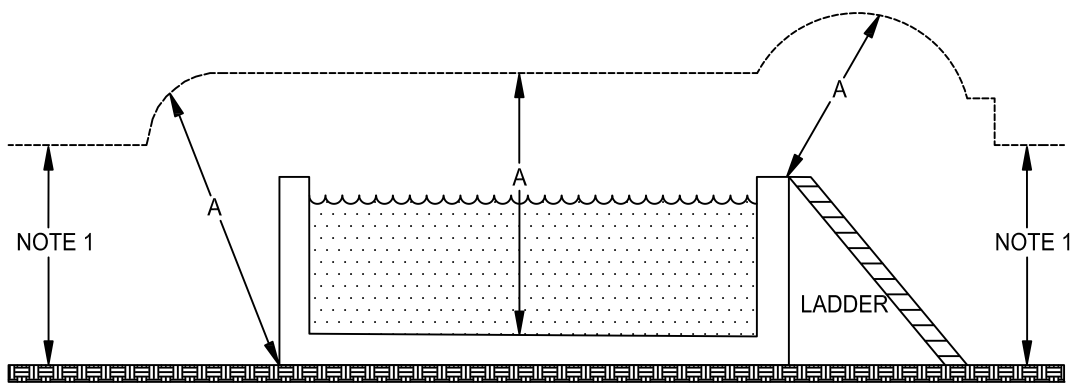
ROCHESTER PUBLIC UTILITIES

NO	REVISION	BY	DATE
0	ORIGINAL DRAWING	BJK	05/01/2017

SERVICE CONDUCTOR CLEARANCES TO ABOVEGROUND SWIMMING POOL WITH DECK

EXHIBIT 4.4

Type of Structure Under or Next to Wire	Neutrals, Guys, Messengers; Surge protection; Wires and Communications	Duplex, Triplex, Quadraplex, Lashed 0 - 750 V	Open Supply Conductors 0 - 750 V	Primary Conductors 750 V - 22 kV
Clearance In Any Direction To: Edge of pool, water surface, Base of diving platform or anchored raft. (Dimension A)	22' - 0"	22' - 6"	23' - 0"	25' - 0"
Hot Tubs and Whirlpool Spas: (Notes 2 and 3)	10' - 6"	11' - 0"	11' - 6"	13' - 6"



ABOVEGROUND SWIMMING POOL WITHOUT DECK. REQUIRED CLEARANCE IS MAINTAINED ABOVE GROUND.

NOTES:

1. 0 - 750 volts except open wire HORIZONTALLY greater than 10 feet from the edge of the pool NEEDS ONLY a vertical clearance of 12.5 feet in pedestrian only traffic areas.
2. For hot tubs and whirlpool spas, clearance is the same as clearance from balconies, decks and areas accessible to pedestrians. Clearance would be from the highest point a person could stand to the conductor.
3. For hot tubs and whirlpool spas, clearance is less than swimming pools since long handled cleaning equipment and rescue poles are not used.

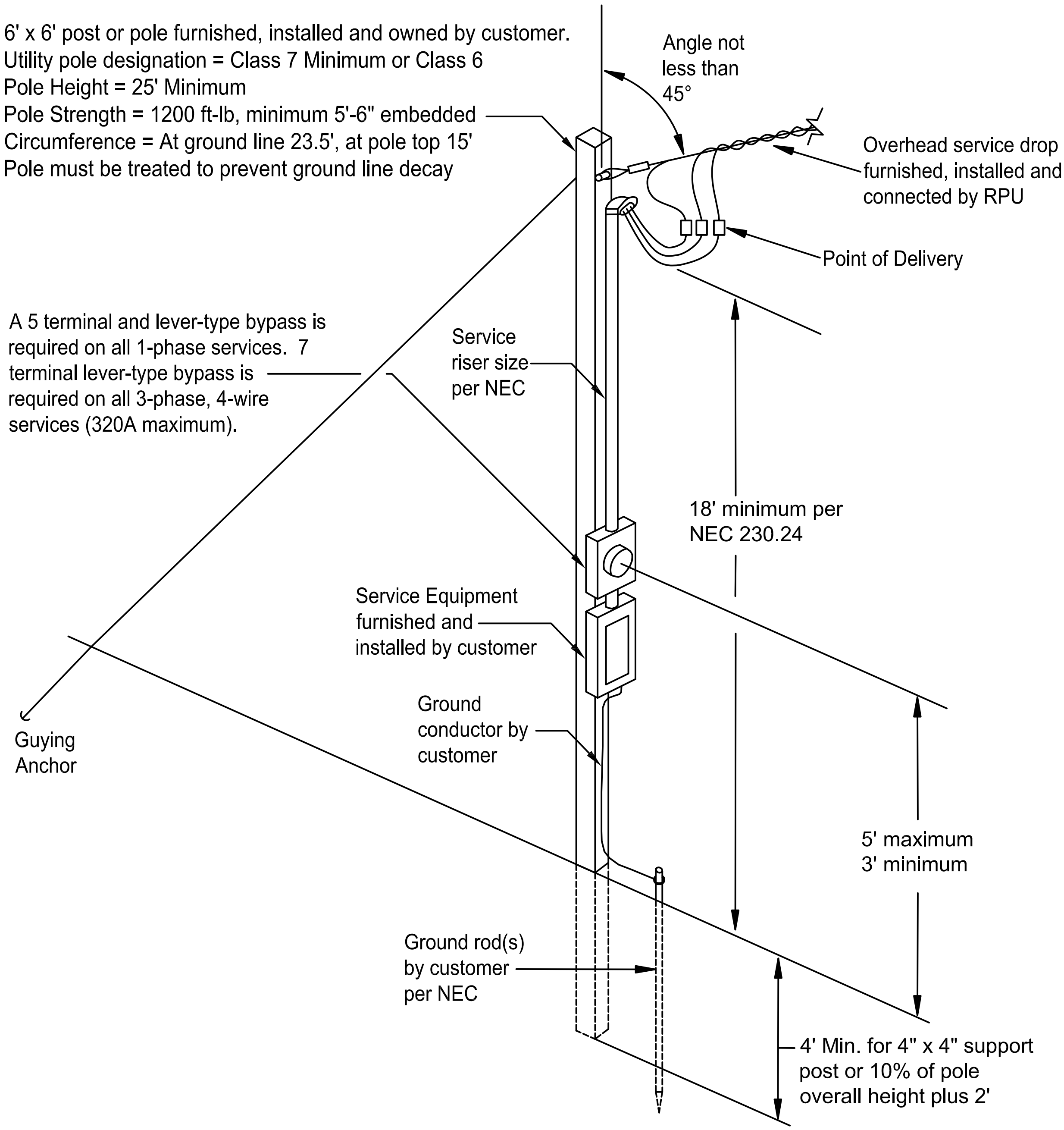
ROCHESTER PUBLIC UTILITIES

NO	REVISION	BY	DATE
0	ORIGINAL DRAWING	BJK	05/01/2017

SERVICE CONDUCTOR CLEARANCES TO ABOVEGROUND SWIMMING POOL WITHOUT DECK

EXHIBIT 4.5

Installation shall be outside the utility easement and located no closer than 10' minimum or 70' maximum with a conductor no larger than 4/0 from RPU's secondary supply point.



NOTES:

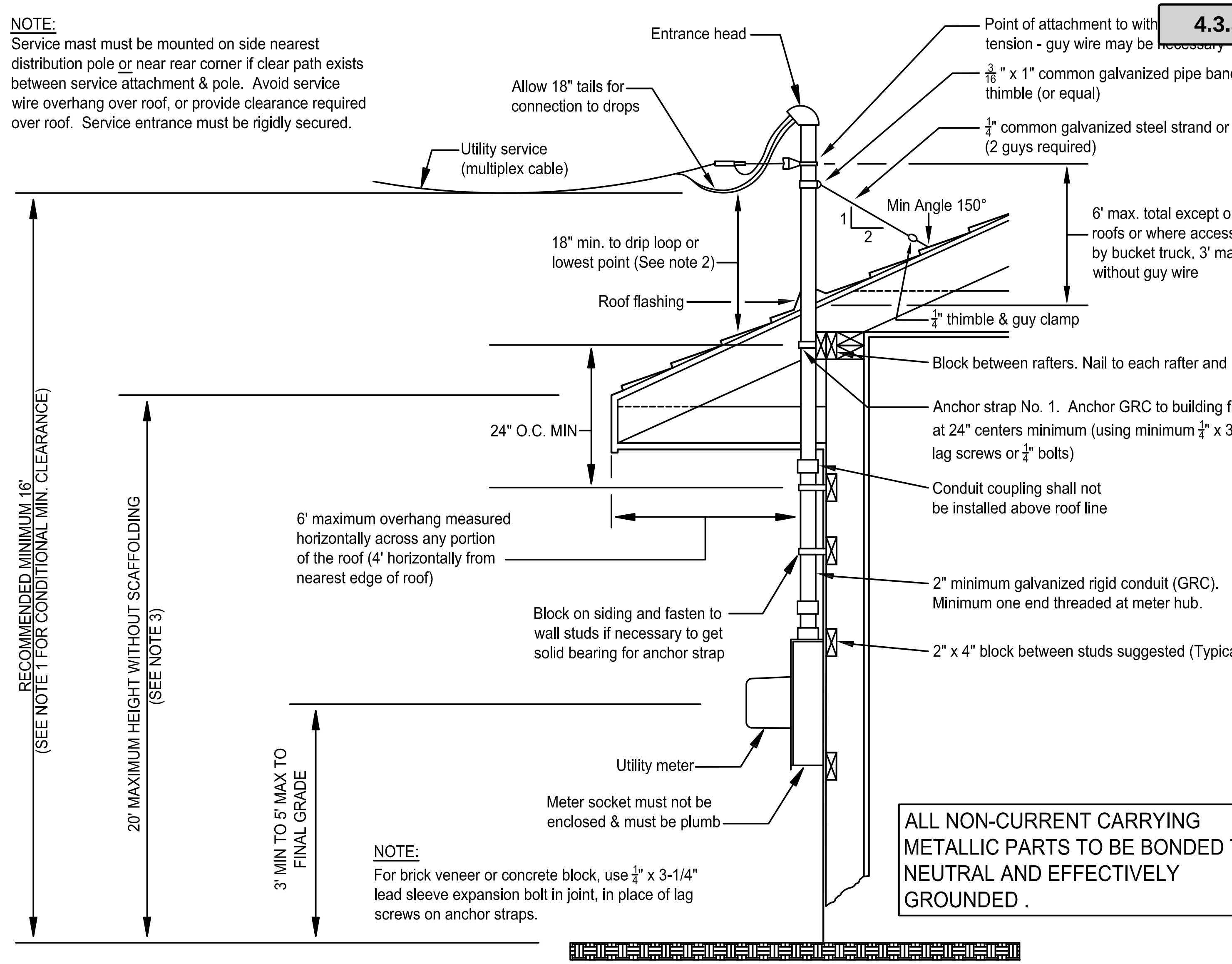
1. Temporary installation shall not be attached to a RPU-owned pole.
2. Support may require additional braces to be protected from vehicular and other construction hazards.
3. Make sure area is clear of underground obstructions before installing support or ground rod.
4. Service drop shall not be at an angle of less than 45° from vertical.

ROCHESTER PUBLIC UTILITIES

NO	REVISION	BY	DATE
0	ORIGINAL DRAWING	BJK	05/01/2017

OVERHEAD SUPPLY SECONDARY TEMPORARY SERVICE INSTALLATION

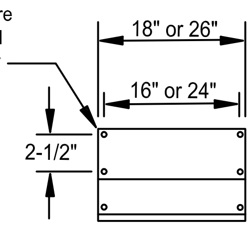
EXHIBIT



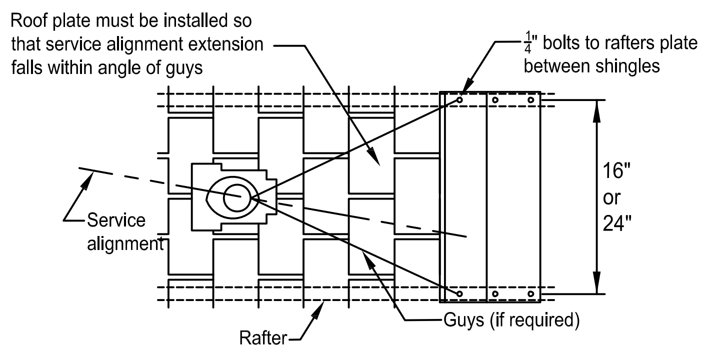
NOTES:

1. If the land under the cable is accessible to truck traffic or to vehicles over 8 feet in height, the minimum attachment height is 16 feet. If the area is subject to pedestrian or restricted traffic only (no vehicles over 8 feet in height), the minimum attachment height is 12 feet; refer to NESC Table 232-1.
2. If the service is crossing the roof for more than 6 feet horizontally in any direction, or more than 4 feet horizontally from the nearest edge of the roof, refer to NESC 234C3 for the appropriate clearance.
3. If the service access point (roof edge, etc.) exceeds 20 foot height above grade, and is not accessible by bucket truck, Customer is required to provide scaffolding or ladder prior to service work being performed. Scaffolding and ladder must meet OSHA safety requirements.

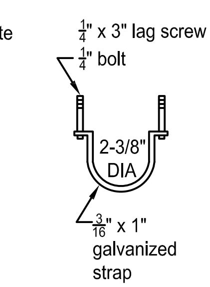
$\frac{3}{8}$" eye bolts & washers with header block are acceptable, but eye lags are not. As an alternate, one guy aligned with the service wire and adequately attached to a $\frac{3}{8}$" eye bolt (not lag) through a header block between rafters is acceptable.



ROOF PLATE (OR EQUAL)



GUY DETAIL



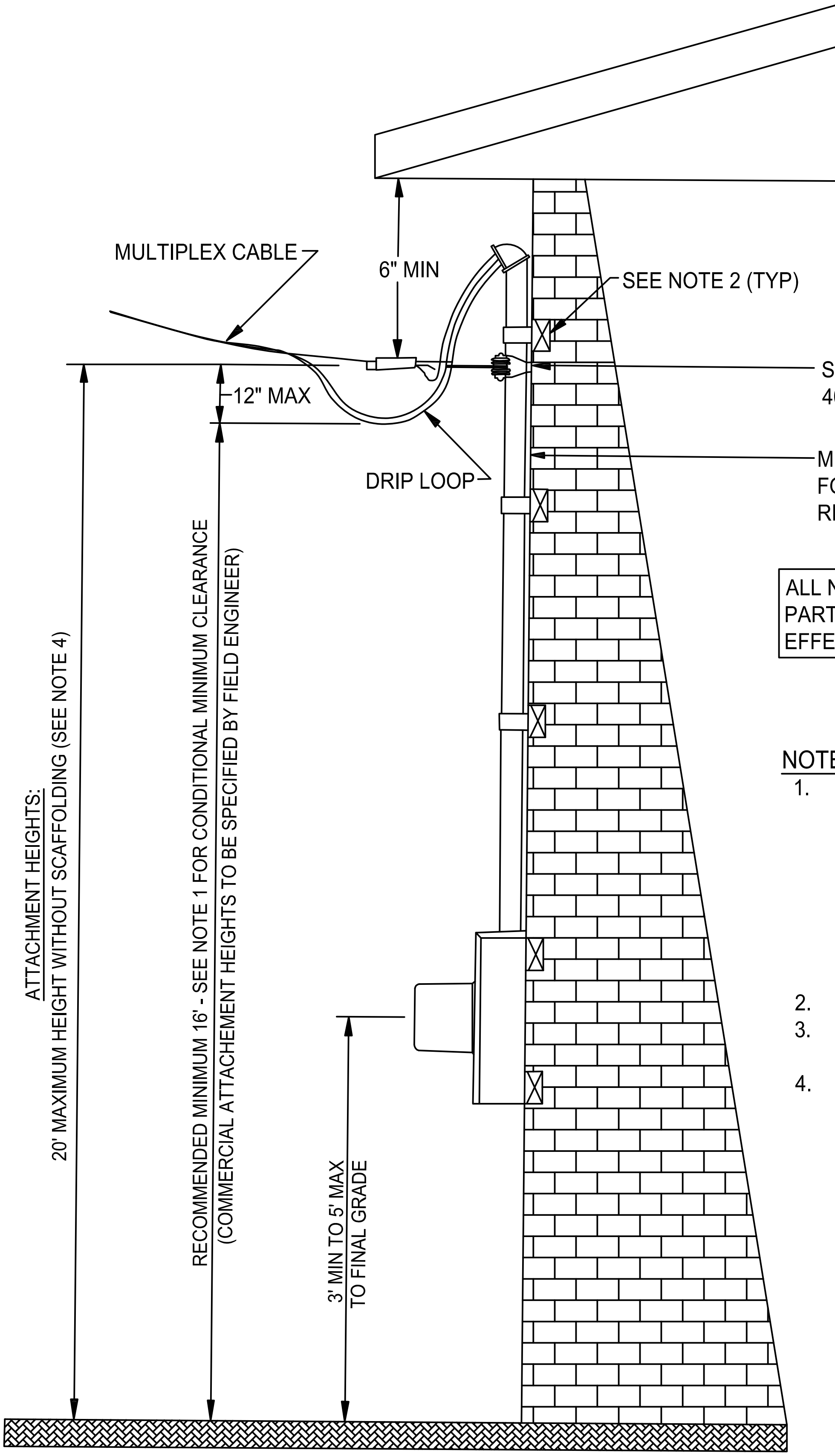
ANCHOR STRAP No. 1(OR EQUAL

ROCHESTER PUBLIC UTILITIES

NO	REVISION	BY	DATE
0	ORIGINAL DRAWING	BJK	05/01/2017

TYPICAL RESIDENTIAL SERVICE MAST INSTALLATION WITH GUYING

EXHIBIT



ALL NON-CURRENT CARRYING METALLIC PARTS TO BE BONDED TO NEUTRAL AND EFFECTIVELY GROUNDED .

NOTES:

1. If accessible to truck or traffic or to other vehicles over 8 feet in height, or to riders on horseback, minimum clearance (and attachment height) is 16 feet; refers to NESC Table 232-1. Clearances shown as 12 feet minimum are suitable for areas subject to pedestrians and restricted traffic only. 2" x 4" blocks betweeen studs is suggested.
2. Anchor to building frame at 24" centers.
3. For clearance of service drops, refer to Sectio 23 of the National Electric Safety Code.
4. If service access point exceeds 20' height abo grade, and is not accessible by bucket truck, customer is required to provide scaffolding or ladder prior to service work performed. Scaffolding & ladder must meet OSHA safety requirements.

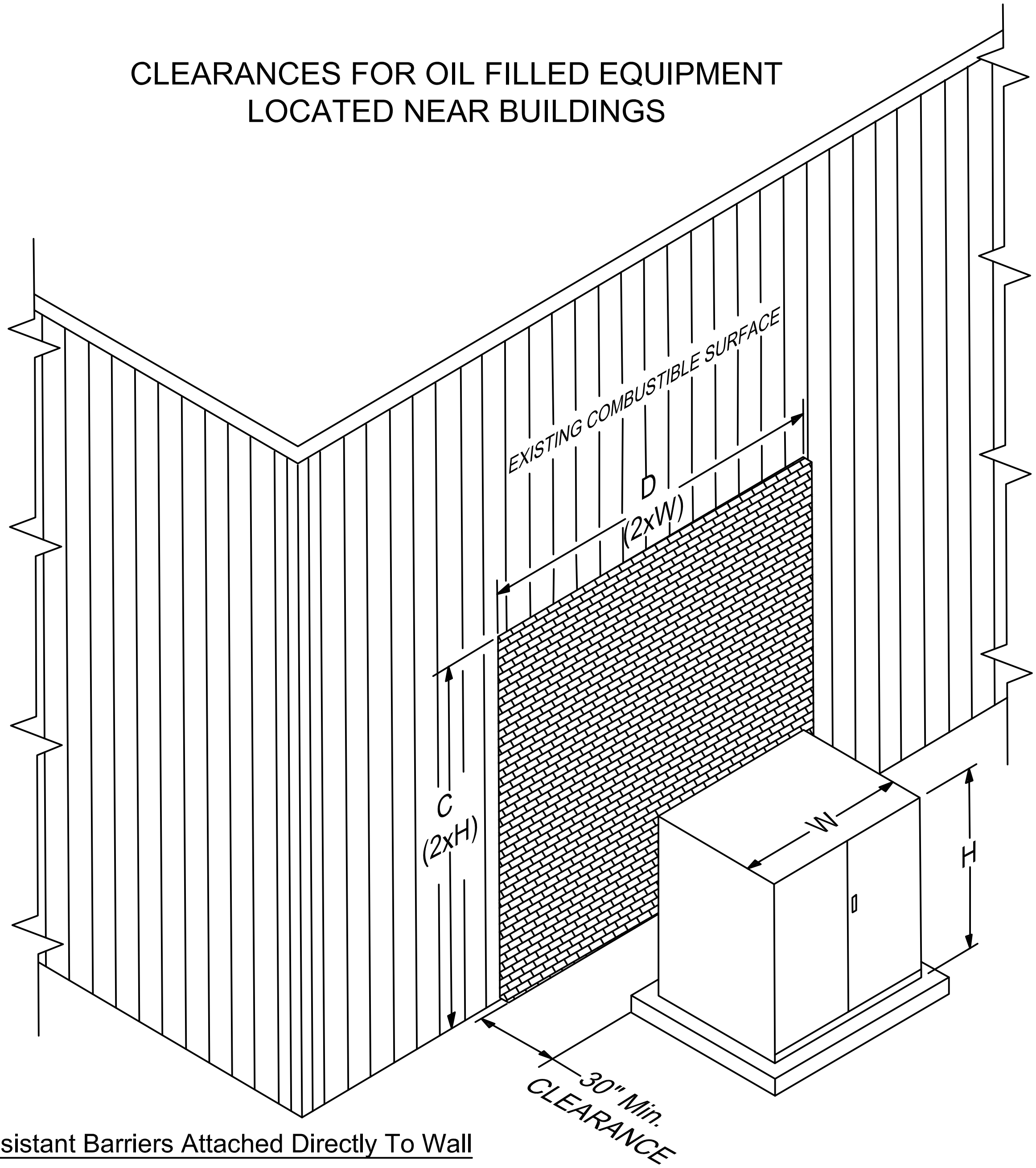
ROCHESTER PUBLIC UTILITIES

NO	REVISION	BY	DATE
0	ORIGINAL DRAWING	BJK	05/01/2017

TYPICAL RESIDENTIAL UNDER EAVES SERVICE INSTALLATION

EXHIBIT

CLEARANCES FOR OIL FILLED EQUIPMENT LOCATED NEAR BUILDINGS



Fire Resistant Barriers Attached Directly To Wall

In locations where basic clearances cannot be met, a fire resistant barrier shall be installed either by the customer or at the customer's expense to reduce the required clearance to combustible walls, door air intakes or windows. The barrier shall be constructed of non-combustible material certified to have a 2 hour fire rating. It shall be of sufficient strength and have stability to resist tipping and satisfy Rochester building ordinances. If a specific ruling regarding fire ratings is necessary, contact the Rochester Fire Department. Engineering will coordinate the construction and location of the barrier, however the customer is responsible for all maintenance. The barrier will satisfy the following dimensional requirements:

H = Height in inches of oil filled equipment.
W = Width in inches of oil filled equipment.
C = Height of barrier required to obtain a projected height of two times the height of the oil filled equipment on the building wall (2 x H).
D = Width of barrier required to obtain a projected width of two times the width of the oil filled equipment on the building wall (2 x W).

ROCHESTER PUBLIC UTILITIES

NO	REVISION	BY	DATE
0	ORIGINAL DRAWING	BJK	05/01/2017

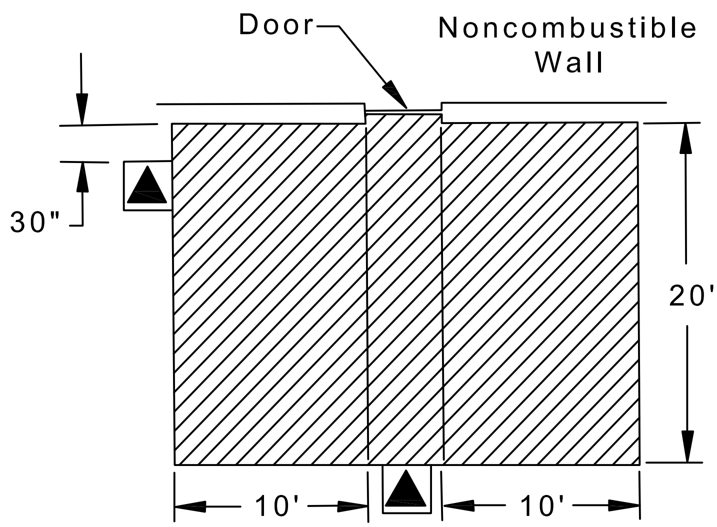
CLEARANCES FOR OIL FILLED EQUIPMENT NEAR BUILDINGS

EXHIBIT

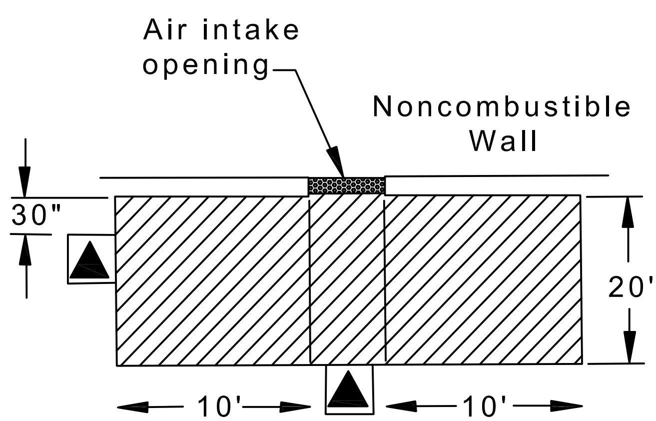
I. NONCOMBUSTIBLE WALLS: (Included in this class would be wood framed brick veneered buildings, metal clad steel framed buildings, cement-board walled metal framed buildings, masonary buildings, and masonary buildings with a one (1) hour fire rating.)

Oil insulated, pad-mounted transformers may be located a minimum distance of 30" from noncombustible walls if all the clearances shown on this and the following drawings are maintained from doors, windows, and other building openings. A sump shall be installed for the transformer if the immediate terrain is not pitched away from the building. If a combustible first floor overhang exists, a 10' distance from the edge of the transformer to the edge of the overhang (combination of vertical and horizontal distance) shall be required in addition to the other clearances shown.

A. Doors
Oil insulated, pad-mounted transformers shall not be located within a zone extending 20' outward and 10' to either side of a building door.



B. Air Intake Openings
Oil insulated, pad-mounted transformers shall not be located within a zone extending 10' outward and 10' to either side of an air intake opening located within 10' of the ground. If the air intake opening is located more than 10' above the ground, the distance from the transformer to the opening shall be a minimum of 25'.



ROCHESTER PUBLIC UTILITIES

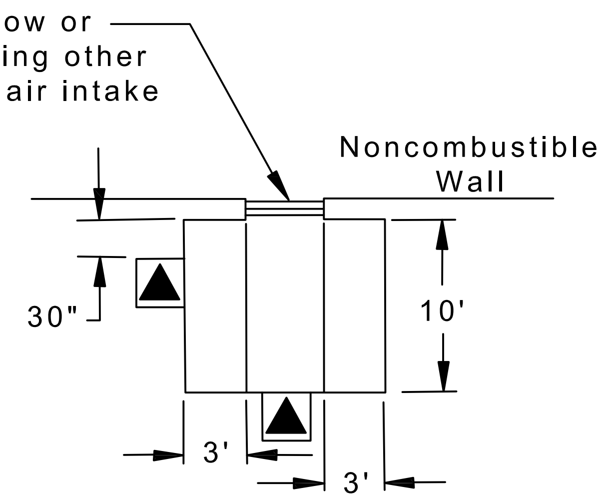
NO	REVISION	BY	DATE
0	ORIGINAL DRAWING	BJK	05/01/2017

PAD-MOUNTED TRANSFORMER LOCATIONS

EXHIBIT 7

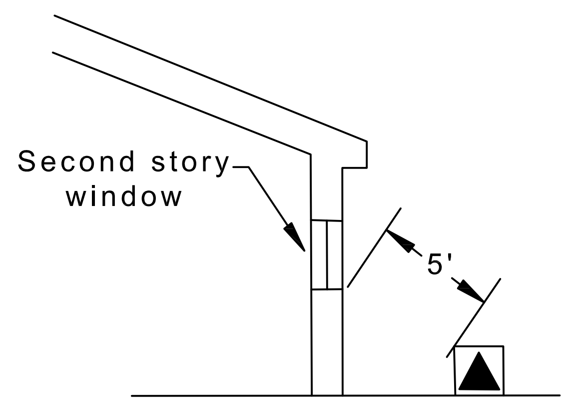
C. Windows or Openings other than Air Intake

1. First Story
Oil insulated, pad-mounted transformers shall not be located within a zone extending 10' outward and 3' to either side of a building window or opening.

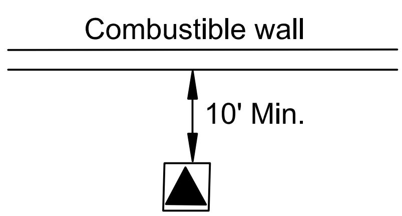


2. Second Story
Oil insulated, pad-mounted transformers shall not be located less than 5' from any part of a second story window or opening.

Oil filled equipment shall not be placed below an operating window on any floor. No exceptions will be made!



II. COMBUSTIBLE WALL
(Included in this class would be wood buildings and metal clad buildings with wood frame construction.)
Oil insulated, pad-mounted transformers shall be located a minimum 10' from the building wall in additio
to the clearance from building doors, windows, and other openings set forth for noncombustible walls.
A sump shall be installed for the transformer if the immediate terrain is not pitched away from the buildin
If a combustible first floor overhang exists, a 10' distance from the edge of the transformer to the edge o
the overhang (combination of vertical and horizontal distance) shall be required in addition to the other clearances as shown.



ROCHESTER PUBLIC UTILITIES

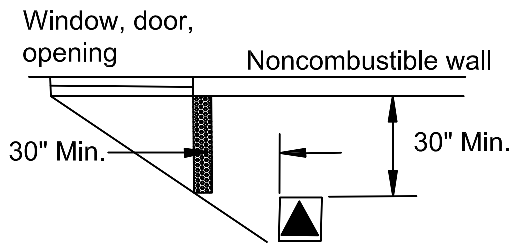
NO	REVISION	BY	DATE
0	ORIGINAL DRAWING	BJK	05/01/2017

PAD-MOUNTED TRANSFORMER LOCATIONS (CONTINUED)

EXHIBI
7

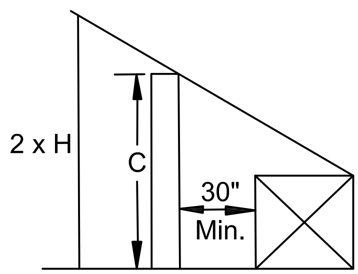
III. BARRIERS

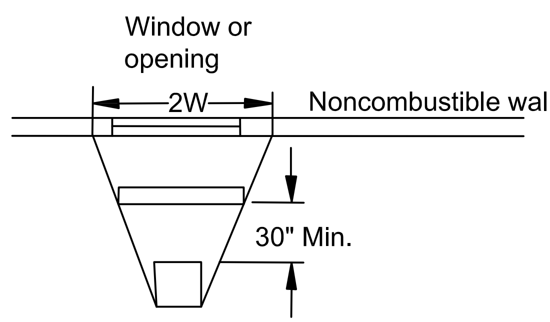
(Included in this class are reinforced concrete, brick, or concrete block barrier walls with a 3 hour fire rating.) If the clearance specified above cannot be obtained, a fire resistant barrier shall be constructed in lieu of the separation. The barrier (when required) is provided by the customer. The following methods of construction are acceptable.



A. NONCOMBUSTIBLE WALL

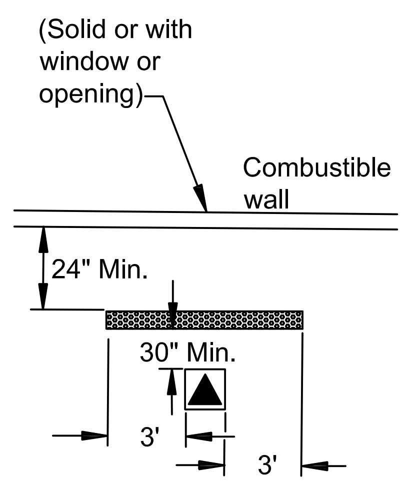
The barrier shall extend to a projection line from the corner of the pad-mounted to the furthest corner of the window, door, or opening in question.





B. COMBUSTIBLE WALLS

The barrier shall extend 3' beyond each side of the oil insulated, pad-mounted transformer. The height of the barrier shall be 3' above the top of the pad-mounted transformer. If a combustible first floor overhang exists, the 24" specified shall be measured from the edge of the overhang rather than from the building wall.



ROCHESTER PUBLIC UTILITIES

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0	ORIGINAL DRAWING	BJK	05/01/2017

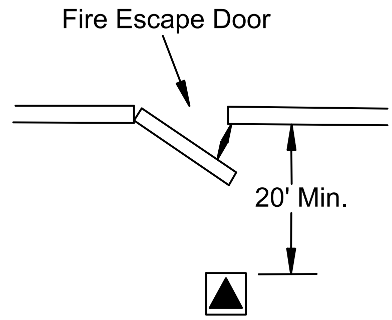
PAD-MOUNTED TRANSFORMER LOCATIONS (CONTINUED)

EXHIBIT 7 (Continued)

IV. FIRE ESCAPES

Oil insulated, pad-mounted transformers shall be located such that a minimum clearance of 20' is maintained from fire escapes at all times.

Exception: Oil insulated, pad-mounted transformers may be located closer to a fire escape than the 20' minimum when a fire resistant barrier is constructed around the transformer (side walls and roof). The barrier shall extend a minimum of 1' beyond the transformer. The transformer and barrier shall not in any way obstruct the fire escape exit. 10' clearance is required in front of pad-mount transformer doors. Adequate transformer accessibility and ventilation must be provided. If transformer is installed underneath a fire escape, maintain 10' vertical clearance.



V. DECORATIVE COMBUSTIBLE ENCLOSURE

Decorative combustible enclosures (fence) installed by the customer around oil insulated, pad-mounted transformers adjacent to a combustible building wall shall not extend more that 24" beyond the transformer towards the combustible wall. 10' clearance is required in front of pad-mounted transformer doors. Adequate transformer accessibility and ventilation must be provided.

ROCHESTER PUBLIC UTILITIES

NO	REVISION	BY	DATE
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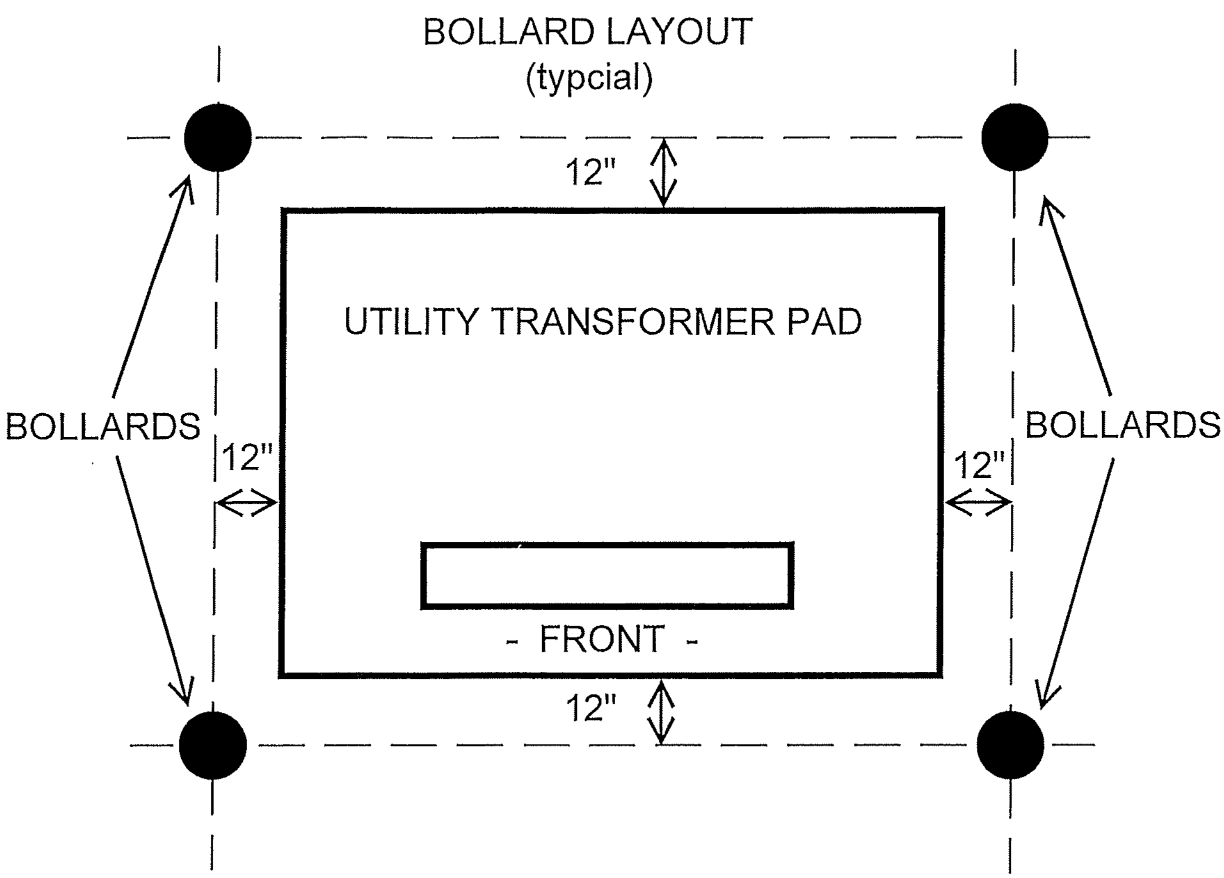
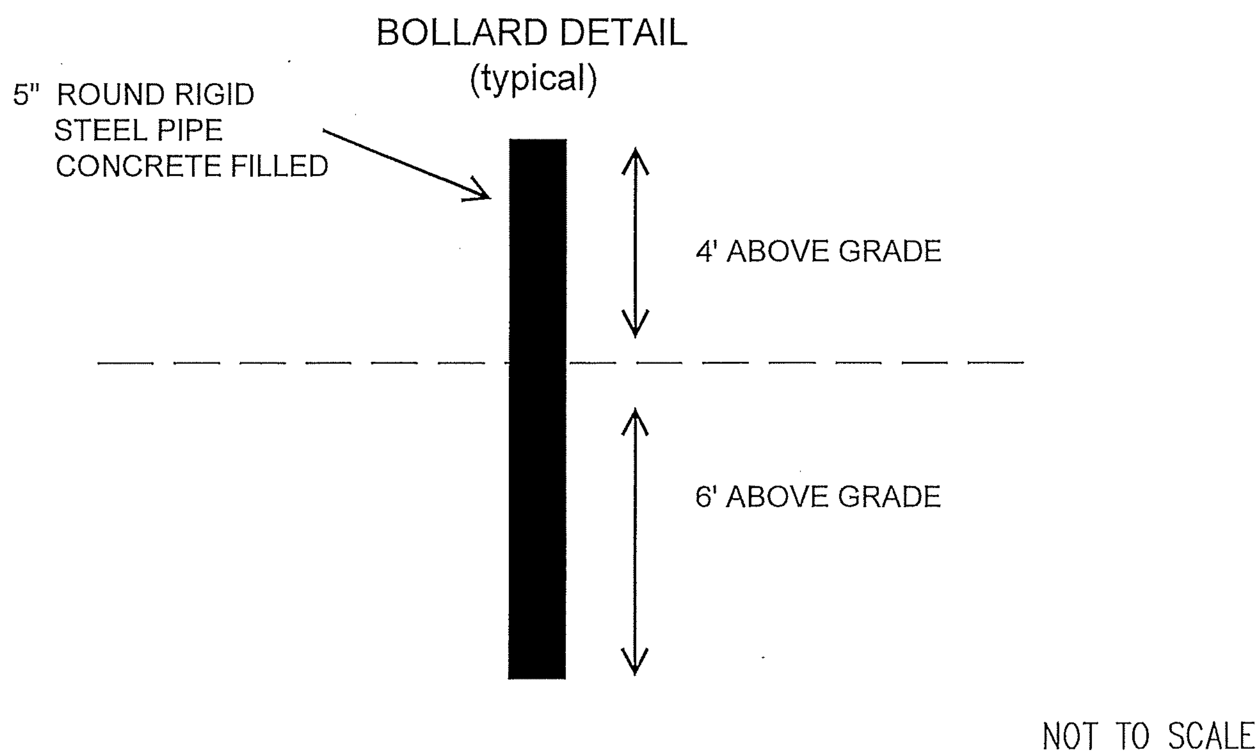
PAD-MOUNTED TRANSFORMER LOCATIONS (CONTINUED)

EXHIBIT 7 (Continued)





ROCHESTER PUBLIC UTILITIES

NO	REVISION	APPROVED BY	DATE
BK	DRAWING CREATED	JSA	5/21

TRANSFORMER PROTECTION

EXHIBIT
7.1

EXHIBIT 8

RPU AND CUSTOMER RESPONSIBILITIES ASSOCIATED WITH NON-SINGLE FAMILY RESIDENTIAL UNDERGROUND INSTALLATIONS

RPU RESPONSIBILITIES

1. Designate service location and/or transformer location.
2. Supply and install pad-mounted transformer.
3. Make all primary terminations and connections.
4. Connect the customer's secondary cable to the secondary terminals of the transformer only after customer's wiring has been approved by the inspecting authority.
5. Energize the service only when authorized to do so by the inspecting authority.
6. Supply and install all primary cable at no cost to the customer after said customer furnishes and installs conduit for the entire distance from the property line to the transformer.
7. Supply and install one meter set for each customer, including all meters required for billing purposes and any accessories such as totalizers, current and potential transformers, phase-shifting transformers, test switches, and color code meter wiring.
8. Inspect customer-furnished equipment required by RPU. Installations not in compliance with RPU regulations will be rejected.

CUSTOMER RESPONSIBILITIES

1. Contact RPU to obtain the location and routing of RPU's facilities and to fill out an Application for Service, Load Data Sheet and any other forms or statements required by RPU.
2. Provide necessary easements and clear area of all construction obstructions.
3. Bring area to final grade before installation of cable and transformers. Grade changes requiring cable adjustments will result in charges to the party requiring the changes.
4. Compaction along conduit route after installation of conduit is the customer's responsibility.
5. Furnish and install a transformer pad and ground rod to RPU specifications. Contact RPU to obtain the pad specifications and transformer location (transformer location shall be truck accessible and within 15 feet of a paved surface) for the specific service being installed. Notify RPU to inspect formed pad prior to pouring concrete.
6. Provide a location for the transformer(s) that meets the clearance requirements of Exhibit 7.
7. Provide easy accessibility to area 24 hours a day.
8. Furnish and install all secondary cables, cabinets, and conduits from the transformer to the building service entrance.

EXHIBIT 8 - Continued

9. Furnish and install electrical conduit per RPU's specifications (typically schedule 40 PVC 4" or larger) with marking tape to the point of interconnection with RPU. All conduit shall be installed a minimum of 36" below final grade. All radiuses less than 60" shall be factory fabricated and shall be made of schedule 40 galvanized rigid metallic conduit. Minimum elbow (bend) radius shall be 36 inches. Furnish and install pull rope in conduit.
10. Install protective bollards if RPU facilities (i.e. transformer, junction cabinet, pad-mount switchgear, etc.) will be installed in parking area or area subject to vehicular traffic.
11. Protect RPU facilities from damage during construction period.
12. Have all required inspections of facility performed and approved.
13 Notify RPU prior to any proposed building or grade changes within 10 feet of the electrical service or the cable route.
14. Supply and install RPU approved meter socket on outside wall or approved location and install conduit for service cable.
15. Notify RPU as far in advance as possible when any unusual loads are anticipated, such as special medical equipment, arc welders, elevators, or any other equipment that could affect RPU's system or any other customer.
16. Pay all applicable RPU fees.

EXHIBIT 9

RPU AND CUSTOMER RESPONSIBILITIES ASSOCIATED WITH UNDERGROUND SINGLE FAMILY RESIDENTIAL DISTRIBUTION (URD) INSTALLATIONS

RPU RESPONSIBILITIES

1. Designate point of delivery or transformer location.
2. Supply and install all primary cable, transformer pads, and pad-mounted transformers.
3. Make all primary terminations and connections and install the grounding system.
4. Connect customer's secondary cables to RPU's point of delivery after customer's wiring has been approved by the inspecting authority.
5. Install the meter and any other meter accessories needed for billing purposes, excluding the meter socket.
6. Energize the service only when authorized to do so by the inspecting authority.
7. Supply and install secondary connection pedestals and secondary cable to the pedestals.

CUSTOMER RESPONSIBILITIES

1. Contact RPU to obtain the location of RPU's facilities and customer service point and to fill out an "Application for Service," and any other forms or statements required by RPU.
2. Provide necessary easements and clear area of all construction obstructions.
3. Bring area to final grade before installation of cable and transformers. Install grade stakes at all front lot line property corners. Grade changes requiring cable adjustments will result in charges to the party requiring the changes.
4. In new developments, install road crossing conduits per Exhibit 12 as designated by RPU in the general development specifications.
5. Allow RPU to install cable/conduit prior to installation of sidewalks, soil or lighting along cable route.
6. Compaction of customer installed (buried) cable is customer's responsibility. (RPU will compact all primary and secondary cable it buries.)
7. Provide firm soil conditions under the pad area to prevent settling of the pad.
8. Provide a location for the transformer or secondary pedestal that meets the clearance requirements outlined in Exhibit 7.
9. Protect RPU facilities from damage during construction period.
10. Provide easy accessibility to the area 24 hours a day.
11. Have wiring approved by inspecting authority and then request service connection by RPU.
12. Install protective bollards if RPU facilities (i.e. transformer, junction cabinet, pad-mount switchgear, etc.) will be installed in parking area or area of vehicular traffic.

EXHIBIT 9 – Continued

13. Notify RPU prior to any proposed building or grade changes within 10 feet of the electrical service or the cable route.
14. Notify RPU as far in advance as possible when any unusual loads are anticipated, such as special medical equipment, arc welders, elevators, or any other equipment that could affect RPU's system or any other customer.
15. Supply and install an RPU approved meter socket on outside wall.
16. Supply all secondary cable extending from the meter to the RPU designated point of interconnection (transformer or secondary pedestal).
17. Contact RPU two (2) business days in advance when a service is to be installed so that RPU can schedule the meeting to provide access to the power source and the contractor can install the service into the power source.
18. Pay all applicable RPU fees.

EXHIBIT 10

INSTALLATION GUIDELINES

Scheduling:

1. RPU will install underground electric facilities on a first come - first served basis. If for some reason the site is not ready for the installation on the scheduled date it will be rescheduled to the end of the queue.

2. New Commercial/Residential Subdivisions are typically installed as joint installations with other utilities. These installations are jointly scheduled by the utilities and our contractor once certain site conditions are met. If for some reason the site is not ready for installation of all facilities on the scheduled date the installation will be rescheduled to the end of the queue.

3. Installation in Unsuitable Backfill Material:

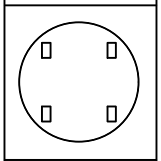
   The customer shall be required to pay an additional fee if unsuitable backfill material is encountered during the installation of RPU's facilities. The fee will be based on the cubic feet of unsuitable backfill material encountered by RPU or our contractor during installation. RPU may require that the Customer pay an estimated fee prior to performing the work.

4. Winter Installations:

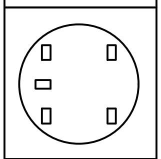
   The customer shall be required to pay a per-foot additional fee for underground cable installation, at the customer's request, after frost has been established in the ground to an average depth of 6 inches or more. The amount of the frost fee depends on the depth of the frost. RPU may require that the estimated frost charges be paid in advance of performing work.

   Installations scheduled on or after the onset of frost will be attempted at the discretion of RPU, based on ground conditions.

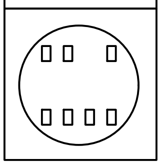
Self-Contained



4 TERMINAL
120-240 VOLT, 277 VOLT
SINGLE PHASE



5 TERMINAL
120-208 VOLT
SINGLE PHASE
(Fifth Terminal needs to be located in the 9 O'Clock Position)



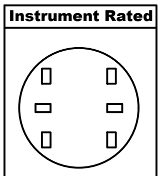
7 TERMINAL
120-208 VOLT
THREE PHASE, 4 WIRE
(Also 240 Volt, 4 Wire Delta)

SELF CONTAINED METERING NOTES:

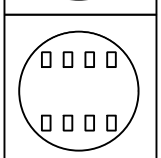
1. **All self contained meter sockets must contain a lever bypass and will need to be purchased by the Customer or Electrician.**

2. **The maximum service size for a self contained metering application is 400A (Class 320 meter socket).**

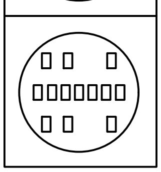
Instrument Rated



6 TERMINAL
120-240 VOLT
SINGLE PHASE



8 TERMINAL
120-240 VOLT
THREE PHASE, 3 WIRE
(Legacy Supported Only - No new installations allowed)



13 TERMINAL
120-208, 240, 277-480 VOLT
THREE PHASE, 4 WIRE

INSTRUMENT RATED METERING NOTES:

1. **All instrument rated meter sockets will need to be purchased by the Customer or Electrician. RPU no longer sells meter sockets.**

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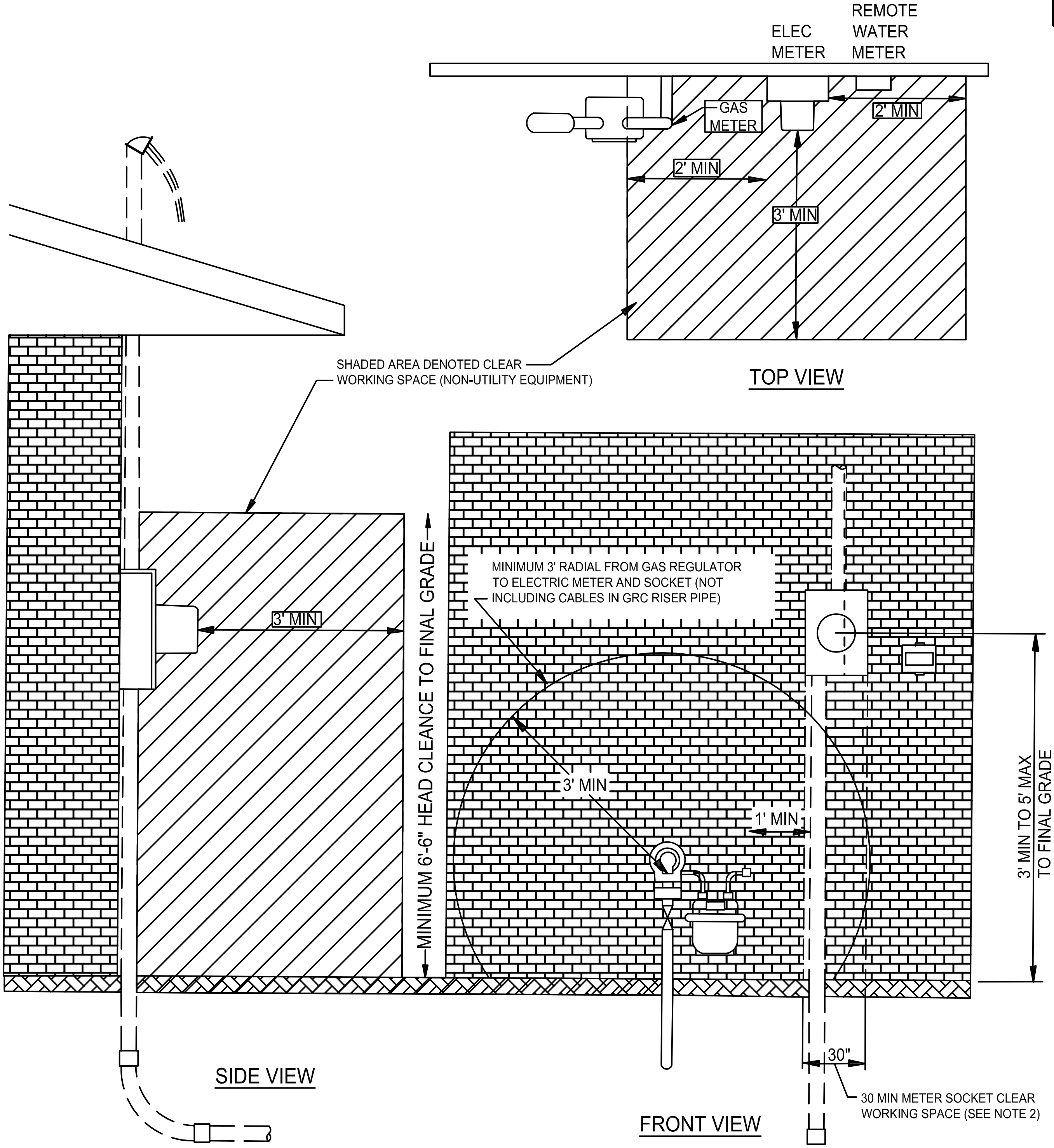
METER SOCKET TYPES

EXHIBIT 11



NOTES:

1. A 30" wide clear working space (includes the meter socket) along with 3' of clear area in front of the meter is required for all non--utility owned equipment. This clear working space shall extend from the final grade up to the required 6'-6" headroom clearance. Obstructions that can hinder maintenance or reading of meters such as shrubs, stairways, window wells, or other debris are prohibited within this clear space.
2. Rochester Building Department requires all above ground gas piping materials to be installed outside of 30" meter socket working space (see drawing).
3. These clearances apply to both overhead and underground services.

ROCHESTER PUBLIC UTILITIES

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0	ORIGINAL DRAWING	BJK	05/01/2017

REQUIRED METER WORKING AND SAFETY CLEARANCES

EXHIBIT

R E S O L U T I O N

BE IT RESOLVED by the Public Utility Board of the City of Rochester, Minnesota, to adopt the proposed 2021 Electric Rules and Regulations, effective July 19, 2021.

Passed by the Public Utility Board of the City of Rochester, Minnesota, this 29th day of June, 2021.

____
President

____
Secretary

FOR BOARD ACTION

Agenda Item # (ID # 13501) Meeting Date: 6/29/2021

SUBJECT: Board Committee Assignments

PREPARED BY: Mark Kotschevar

ITEM DESCRIPTION:

The Board Organization policy states: "The Board President shall, each year at the first regular meeting after election, appoint each Board member to serve as a Board-Management liaison for the following functions:

Finance/Accounting Audit

Communications

Strategic Planning

Operations and Administration

Policy

In addition, the Board created an additional committee on Rates in 2019.

Attached for your consideration is a table denoting the committee assignments discussed at last month's meeting.

UTILITY BOARD ACTION REQUESTED:

Appoint committee assignments

Public Utility Board Committee Assignments 2021-22					
Finance	**Communications**	**Strategic Planning**	**Operations & Admin.**	**Policy**	**Rates**
Melissa Graner Johnson	Melissa Graner Johnson	Tim Haskin	Tim Haskin	Brian Morgan	Patrick Keane
Brett Gorden	Tim Haskin	Brian Morgan	Melissa Graner Johnson	Brett Gorden	Brett Gordon
Peter Hogan	Steven Nyhus	Jeremy Sutton	Jeremy Sutton	Mark Kotschevar	Mark Kotschevar
	Krista Boston	Peter Hogan	Scott Nickels		

FOR BOARD ACTION

Agenda Item # **(ID # 13500)** **Meeting Date: 6/29/2021**

SUBJECT: Strategic Planning

PREPARED BY: Mark Kotschevar

ITEM DESCRIPTION:

At its February meeting, the Board reviewed our existing 2018-2020 strategic plan and provided input into the 2022-2024 update. We have incorporated that input into an updated 2022-2024 Strategic Plan Overview document along with creating a 3-year road map with specific outcomes to be achieved each year. These documents are attached for your review and comment. We welcome any feedback and once finalized, these will guide the creation of our 5-year budget.

UTILITY BOARD ACTION REQUESTED:

N/A Informational only

Customer Focused And Empowered Employees

RELATIONSHIP

DEFINITION: We will foster a culture that enriches the lives of our customers.

INCLUDED IN THIS AREA: We will be proactive, responsive, and dependable in creating partnerships with our customers by leveraging our relationships, experience, listening and anticipating how we can best meet their expectations. We will employ and develop people who are passionate about delivering quality customer service.

THE FUTURE LOOKS LIKE:

- We understand what our customers value, who they are, their challenges and needs, and the ways in which they want to interact with us.
- We have a culture of caring, inclusive, compassionate service delivery that aligns with customers' needs and values.
- We empower and recognize RPU employees that provide best in class customer experience with a lens toward equitable customer-centered service.

Engaged With Our Community

REPUTATION

DEFINITION: We will deliver world-class service to our customers and be a trusted partner.

INCLUDED IN THIS AREA: We will employ an empowered workforce that acts in the best interest of our customers and the community. Our actions will demonstrate transparency, honesty, respect, expertise, and good faith. This will result in us being held in high esteem within our industry and by our stakeholders.

THE FUTURE LOOKS LIKE:

- RPU is represented on key boards, tasks forces, industry groups, and community organizations where RPU's mission is impacted.
- RPU has strong positive relationships with policy makers, neighborhoods, utilities, and other industry coalitions.
- We maintain a greater than 90% rate of customer satisfaction.
- RPU is engaged with the community and viewed as a trusted professional resource.
- We have a welcoming environment in which all customers can participate in the public process.

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2022-2024 STRATEGIC PLAN OVERVIEW

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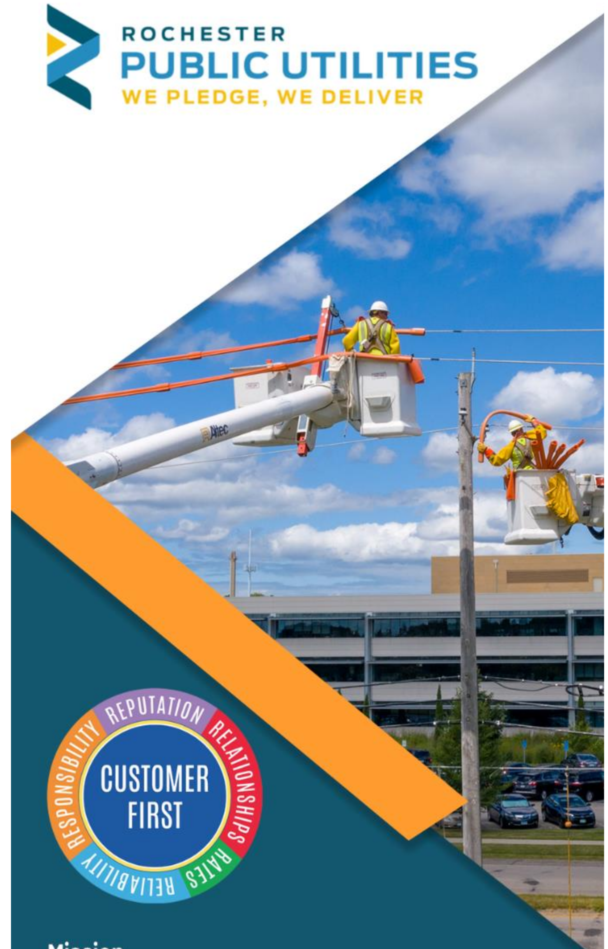

REPUTATION
RELATIONSHIPS
RATES
RELIABILITY
RESPONSIBILITY
CUSTOMER FIRST

Mission
We provide the highest quality services and products for our customers. With our experience and resoures, we enrich people's lives, help businesses prosper, and promote the community's welfare.

Vision
We will set the standard for service.

Maintain Rates that Provide Value and Long Term Financial Stability

RATES

DEFINITION: We will maintain rates that provide value and long-term financial sustainability.

INCLUDED IN THIS AREA: Our rates are competitive, fair, equitable, defensible, and cost-based. Our rates support innovation, conservation, growth, strategic investments, as well as sustain financial health, provide a return to the community, and support reliability, safety and responsiveness.

THE FUTURE LOOKS LIKE:

- We use cost causation principles in our rate design to encourage efficient electrification, promote conservation, reduce total costs to our customers and reduce cross subsidization within/between customer classes.
- Our rates deliver value by being competitive with electric and water rates of similar utilities in our area.
- RPU maintains cash reserves, debt coverage, and equity to earn an AA or better bond rating.

Leaders in Service And System Reliability

RELIABILITY

DEFINITION: We will maintain optimal levels of reliability by balancing system investments and prudent utility practices for both water and electric services, without compromising the safety of our employees or the public.

INCLUDED IN THIS AREA: We will consider reliability and resiliency impacts when making new infrastructure investments. We will be committed to proactive preventative maintenance and infrastructure improvements. We will maintain a culture of compliance with the regulatory agencies that oversee our electric and water industry.

THE FUTURE LOOKS LIKE:

- Water and electric outage indices that are above industry standards.
- Reliability is a major driver in future power supply decisions and strategic investments.
- Compliance programs are proactive, dynamic and resourced.

Seen as Stewards of the Resources We Impact

RESPONSIBILITY

DEFINITION: We will foster a consistent cultur of excellence in achieving and maintaining RPU's responsibilities to our employees, customers, community, external partners, regulators, and environment.

INCLUDED IN THIS AREA: We commit to utilize the best commercially available and cos effective technologies and tools to effectively manage energy and water usage. We will refle the standards and vision of the community in tl selection of resources and programs. We will continue to be good stewards of resources anc to treat customers and employees fairly and ethically. We will communicate personal accountability to all our employees and promot a culture of continuous improvement.

THE FUTURE LOOKS LIKE:

- A culture of safety that promotes situational awareness, collaboration to prevent workplace hazards, and regular education with zero recordable injuries as our standarc
- A culture of environmental stewardship that promotes conservation of resources with ze environmental violations as our standard.
- A culture that educates, equips, and empowers our employees to live our organizational core values.
- An organizational focus that utilizes partnerships to leverage our assets in order to enrich our customers and the community.

Reliability

The future looks like…		
• Water and electric outage indices that are above industry standards. • Reliability is a major driver in future power supply decisions and strategic investments. • Compliance programs are proactive, dynamic, and resourced.		

2022	2023	2024
• Commitment of strategic investments in SLP to ensure reliability of steam supply. • Impacts to reliability of the 2030 plans are fully understood and key milestones are determined. • Maintain above average industry reliability and compliance metrics. • Enhance the Incident Response Plan.	• Maintain above average industry average reliability and compliance metrics. • IT security to detect and respond while supporting usability. • Incidence Response Plan implementation. • Implement the outcome of the strategic SLP commitment. • 2030 direction established.	• Maintain above average industry reliability and compliance metrics. • Explored all alternatives to capacity (power supply requirements).

Rates

The future looks like…

- We use cost causation principles in our rate design to encourage efficient electrification, promote conservation, reduce total costs to our customers and reduce cross subsidization within/between customer classes.
- Our rates deliver value by being competitive with electric and water rates of similar utilities in our area.
- RPU maintains cash reserves, debt coverage, and equity to earn an AA or better bond rating.

2022	2023	2024
• Overlay 2030 resource plan with the financial plan to understand future rates. • Implement the Electric Cost of Service recommendations. • Complete Water cost of service study.	• Update 2030 financial plan to understand impact on future rates. • Electric cost of service study complete with focus on demand thresholds and rate consolidation.	• Rate consolidation consideration based on cost of service. • Financing plan completed for 2030 decision.

Reputation

The future looks like…

- RPU is represented on key boards, tasks forces, industry groups, and community organizations where RPU's mission is impacted.
- RPU has strong positive relationships with policy makers, neighborhoods, utilities, and other industry coalitions.
- We maintain a greater than 90% rate of customer satisfaction.
- RPU is engaged with the community and viewed as a trusted professional resource.
- We have a welcoming environment in which all customers can participate in the public process.

2022	2023	2024
• Identify gaps and areas for improvement in representation. • RPU has established **DEI** (Diversity, Equity & Inclusion) goals within City plan. • Maintain Customer Satisfaction levels of 90%+ and develop Commercial Customer Satisfaction survey.	• Consistency of education and message to each stakeholder group. Every employee equipped to tell our story. • Targeted plan to engage customers, industry and policy-makers. • Implementation plan of RPU's established DEI goals within the City Plan. • Close gaps that were identified in the Commercial Customer Survey (from 2022).	• Every employee understands expectations of them in being the **POWER of ONE.** • We are represented or in the process of representation for all identified boards and committees. • Maintain Residential and Commercial Satisfaction levels of 90%+.

Relationships

The future looks like…

- We understand what our customers value, who they are, their challenges and needs, and the ways in which they want to interact with us.
- We have a culture of caring, inclusive, compassionate service delivery that aligns with customers' needs and values.
- We empower and recognize RPU employees that provide best in class customer experience with a lens toward equitable customer-centered service.

2022	2023	2024
• Identified customer segments. • Fully documented customer experience maps. • Develop the technical environment to enable data access for future analytics and decision-making. • Gap analysis and identification of training needs to achieve identified DEI goals	• Completed customer experience strategy for future experience/service. (includes process, culture and technology) • Developed capability to create actionable information on customer segmentation. (data analytics) • Customer service training inclusive of DEI goals	• We differentiate between segments and utilize in all programs and rate development. • Culture of data driven decision-making.

Responsibility

The future looks like…

- A culture of safety that promotes situational awareness, collaboration to prevent workplace hazards, and regular education with zero recordable injuries as our standard.
- A culture of environmental stewardship that promotes conservation of resources with zero environmental violations as our standard.
- A culture that educates, equips, and empowers our employees to live our organizational core values.
- An organizational focus that utilizes partnerships to leverage our assets in order to enrich our customers and the community.

2022	2023	2024
• Succession plan for essential functions. • Renewable energy plan and decision for community solar. • Identify opportunities for improvement in compliance processes and measurements.	• Every employee has an identified development plan that is leveraged each year in a review process. • Implement key controls to identify and mitigate potential compliance variances with measurements of progress.	• Measure, monitor and modify key controls.

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FOR BOARD ACTION

Agenda Item # **(ID # 13504)** **Meeting Date: 6/29/2021**

SUBJECT: Adjustment of Utility Services Billed Policy

PREPARED BY: Peter Hogan

ITEM DESCRIPTION:

As part of the RPU Board Policy review process, the board committee and staff have updated and renamed the Adjustment of Electric and Water Bills Policy to include:

- Meter accuracy parameters for water meters,
- Updated the look back periods for both over charges and undercharges, and
- Added guidance for payment agreements when correcting for undercharges.

These changes are being recommended to bring the current policy into compliance with MN Statute 216B.098 Residential Customer Protections. The policy title is being updated to encompass all the utility services that RPU currently bills for or may bill for in the future.

A redline and clean copy of the Adjustment of Utility Services Billed Policy is attached.

UTILITY BOARD ACTION REQUESTED:

Staff recommends the Board approve the amended Adjustment of Utility Services Billed Policy

ROCHESTER PUBLIC UTILITIES
BOARD POLICY STATEMENT

POLICY SUBJECT: ADJUSTMENT OF ~~ELECTRIC AND WATER BILLS~~ UTILITY SERVICES BILLED

POLICY OBJECTIVE:

Rochester Public Utilities makes every effort to eliminate billing errors to customers for the use of utility services. However, billing errors may occur as a result of many different circumstances. This policy sets forth a standard method for adjusting overcharged and undercharged customer utility accounts.

POLICY STATEMENT:

1. Billing Errors

When a customer has been overcharged or undercharged as a result of an incorrect reading of the meter, incorrect application of the rate schedule, incorrect connection of the meter, application of an incorrect multiplier or constant, or other similar reasons, the amount of the overcharge shall be refunded to the customer or the amount of the undercharge will be billed to the customer.

2. Inaccurate Meters

Whenever any water or electric meter is found upon testing to have and average error of more than the following:

Electric Meters – Watt Hour Meter (2%), Demand Meter (1.5%)
Water Meters – Displacement, Turbine and Ultrasonic Meters (1.5%), Compound (3%)
~~watt-hour meter is found upon testing to have an average error of more than two percent (2%) or a demand meter more than one and one-half (1.5%),~~

~~a~~A recalculation of bills for service will be made on the basis that the meter should be one hundred percent (100%) accurate with respect to a working test standard. The refund or charge shall be based on the (actual) meter reading obtained by the RPU representative, averaging the amount registered over corresponding periods in previous months or averaging usage accumulated on the new meter.

3. Meter Fails to Register Usage or Registers Intermittently

When the error cannot be determined by testing because the meter is not registering or is registering intermittently, RPU will charge for an estimated amount of usage. This amount shall be calculated by averaging the amounts registered over corresponding periods in previous months. In the absence of such information, the average usage accumulated on the new meter will be the amount billed.

4. Refund or Charge Period

The maximum refund period will be three years from the date of discovery of an overcharge. The maximum billing adjustment period will be one year before the discovery of an undercharge, unless meter tampering is involved. ~~The maximum charge period will be one year unless meter tampering is involved.~~ If meter tampering is involved, the maximum ~~charge~~ billing adjustment period will be ~~six years~~ based on the date of the earliest evidence of meter tampering.

The utility shall offer a payment agreement to customers who have been undercharged if no culpable conduct by the customer or resident of the customer's household caused the undercharge. The agreement will cover a period equal to the time over which the undercharge occurred or a different time period that is mutually agreeable to the customer and the utility, except that the duration of a payment agreement offered by a utility to a customer whose household income is at or below 50 percent of state median household income will consider the financial circumstances of the customer's household.

No interest or delinquency fee will be charged as part of an undercharge agreement provided the payment agreement is maintained.

If a customer inquiry or complaint results in the utility's discovery of the undercharge, the utility will bill for undercharges incurred after the date of the inquiry.

~~The maximum refund period will be six years.~~

5. Refunding or Billing Adjustments

Refunds to existing customers will be handled as a credit on the customer's billing. At the customer's request, the credit may be refunded after deducting any outstanding balances.

If a refund is due a customer who no longer has an active service, a letter is mailed to the last known address.

If the adjustment creates a balance due the utility for a current customer, ~~a letter is mailed to that customer~~ the customer will be contacted with an explanation of ~~explaining the~~ charges. In addition, ~~along with~~ a corrected billing statement will be mailed to the customer.

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RELEVENT LEGAL AUHORITY:
Minnesota Statutes 216B

EFFECTIVE DATE OF POLICY: February 8, 1994

REVISED: June 29, 2021

POLICY APPROVAL:

____
Board President

____
Date

RESOLUTION

BE IT RESOLVED by the Public Utility Board of the City of Rochester, Minnesota, to approve the Adjustment of Utility Services Billed Policy, attached.

Passed by the Public Utility Board of the City of Rochester, Minnesota, this 29th day of June, 2021.

President

Secretary

ROCHESTER PUBLIC UTILITIES
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RELEVENT LEGAL AUHORITY:
Minnesota Statutes 216B

EFFECTIVE DATE OF POLICY: February 8, 1994

REVISED: June 29, 2021

POLICY APPROVAL:

Board President

Date

FOR BOARD ACTION

Agenda Item # **(ID # 13517)** **Meeting Date: 6/29/2021**

SUBJECT: RPU Index of Board Policies

PREPARED BY: Christina Bailey

ITEM DESCRIPTION:

UTILITY BOARD ACTION REQUESTED:

ROCHESTER PUBLIC UTILITIES		
INDEX OF BOARD POLICIES		
	REVISION DATE	RESPONSIBLE BOARD COMMITTEE
BOARD		
1. Mission Statement	6/26/2012	Policy
2. Responsibilities and Functions	3/27/2012	Policy
3. Relationship with the Common Council	2/28/2012	Policy
4. Board Organization	3/27/2018	Policy
5. Board Procedures	3/27/2012	Policy
6. Delegation of Authority/Relationship with Management	7/24/2018	Policy
7. Member Attendance at Conferences and Meetings	12/18/2018	Policy
8. Board Member Expenses	12/18/2018	Policy
9. Conflict of Interest	11/26/1985	Delete
10. Alcohol and Illegal Drugs	7/28/1988	Delete
11. Worker Safety	3/27/2012	Policy
CUSTOMER		
12. Customer Relations	4/30/2019	Ops & Admin
13. Public Information and Outreach	4/30/2019	Communications
14. Application for Service	7/1/2016	Ops & Admin
15. Electric Utility Line Extension Policy	3/28/2017	Finance
16. Billing, Credit and Collections Policy	5/25/2021	Finance
17. Electric Service Availability	10/29/2019	Ops & Admin
18. Water and Electric Metering	6/26/2018	Ops & Admin
19. Electric & Water Bill Adjustment	3/10/1994	Finance
20. Rates	7/25/2017	Finance
21. Involuntary Disconnection	4/24/2018	Communications
ADMINISTRATIVE		
22. Acquisition and Disposal of Interest in Real Property	12/19/2017	Ops & Admin
23. Electric Utility Cash Reserve Policy	1/28/2020	Finance
24. Water Utility Cash Reserve Policy	1/28/2020	Finance
25. Charitable Contributions	6/25/2019	Communications
26. Utility Compliance	10/24/2017	Communications
27. Contribution in Lieu of Taxes	6/29/1999	Finance
28. Joint-Use of Infrastructure and Land Rights	3/30/2021	Ops & Admin
29. Customer Data Policy	10/9/2014	Communications
30. Life Support	9/24/2019	Communications
31. Electric Utility Undergrounding Policy	9/29/2020	Ops & Admin
Red - Currently being worked on		
Yellow - Will be scheduled for revision		

Attachment: Index of Board Policies-revised (13517 : RPU Index of Board Policies)

FOR BOARD ACTION

Agenda Item # **(ID # 13522)** **Meeting Date: 6/29/2021**

SUBJECT: Division Reports & Metrics - June 2021

PREPARED BY: Christina Bailey

ITEM DESCRIPTION:

UTILITY BOARD ACTION REQUESTED:

Division Reports & Metrics June 2021

CORE SERVICES
SAFETY, COMPLIANCE & PUBLIC AFFAIRS
POWER RESOURCES
CUSTOMER RELATIONS
CORPORATE SERVICES
FINANCIAL REPORTS

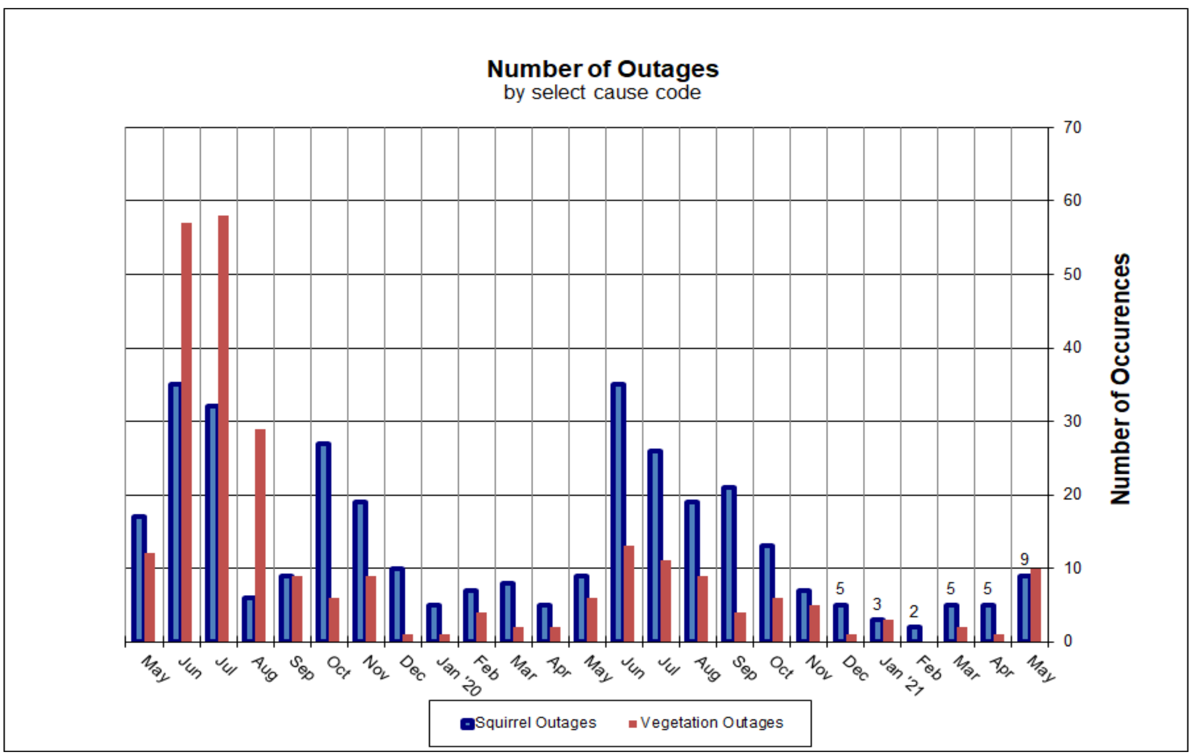
Division Reports & Metrics
June 2021

CORE SERVICES

Electric Utility:

1. **Electric Outage Calculations for the month and year to date (May 2021 Data)**
   a. Reliability = 99.98289% Year-to-date Reliability = 99.99322%
   b. 6,405 Customers affected by Outages Year-to-date Customers affected by Outages = 16,020
   c. SAIDI = 7.64 min Year-to-date SAIDI = 3.01 min
   d. CAIDI = 61.24 min Year-to-date CAIDI = 50.68 min

2. **Electric Utility Operations – T&D, Engineering, System Ops, GIS, Tech Services**:
   - Annual electric field crew skills assessment and field safety training successfully completed.
   - Design phase of the Marion Road substation is on-going on specific equipment. The Request for Bid for site construction has been released in June, with bids due in July.
   - The SCADA upgrade is scheduled to be completed on June 30, 2021. This project is on schedule and on budget.
   - Reliability statistics were negatively impacted in May due to vehicle accidents and stormy spring weather.



- Summary of individual electrical outages (greater than 200 customers – May 2021 data)

# Customers	Date	Duration	Cause
1,924	5/2/21	2h 49m	Vehicle Hit Pole
1,563	5/6/21	1h 15m	Overhead Equipment
998	5/5/21	2h 10m	Overhead Equipment
593	5/1/21	40m	Overhead Equipment
591	5/14/21	7m	Vehicle Hit Pole
225	5/2/21	1h 22m	Overhead Equipment

- Summary of aggregated incident types (greater than 200 customers – May 2021 data)

# Customers	Total # of Incidents	Cause
3,598	14	Overhead Equipment
2,527	4	Vehicle Hit Pole
556	10	Vegetation
214	9	Animals

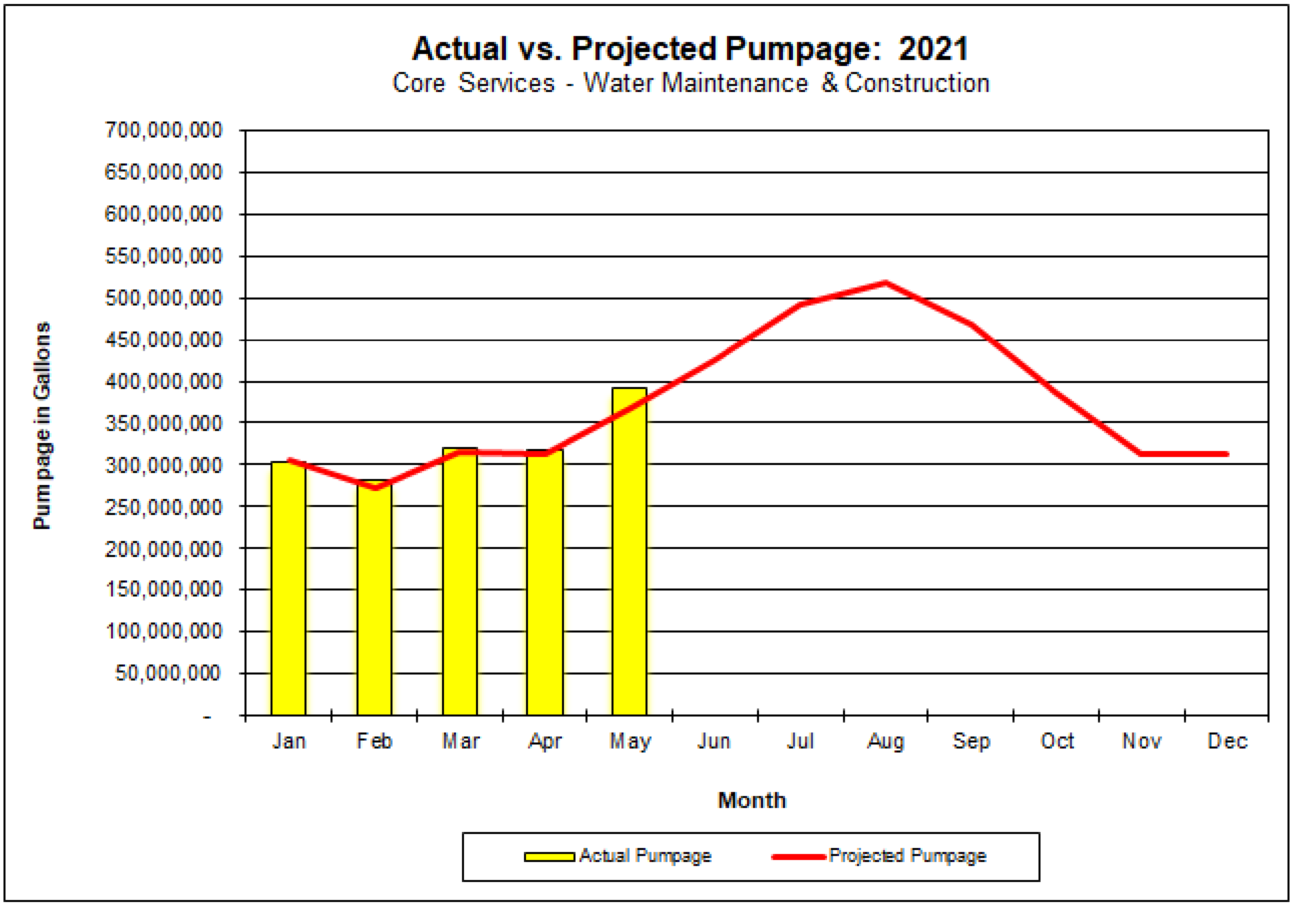
Water Utility:

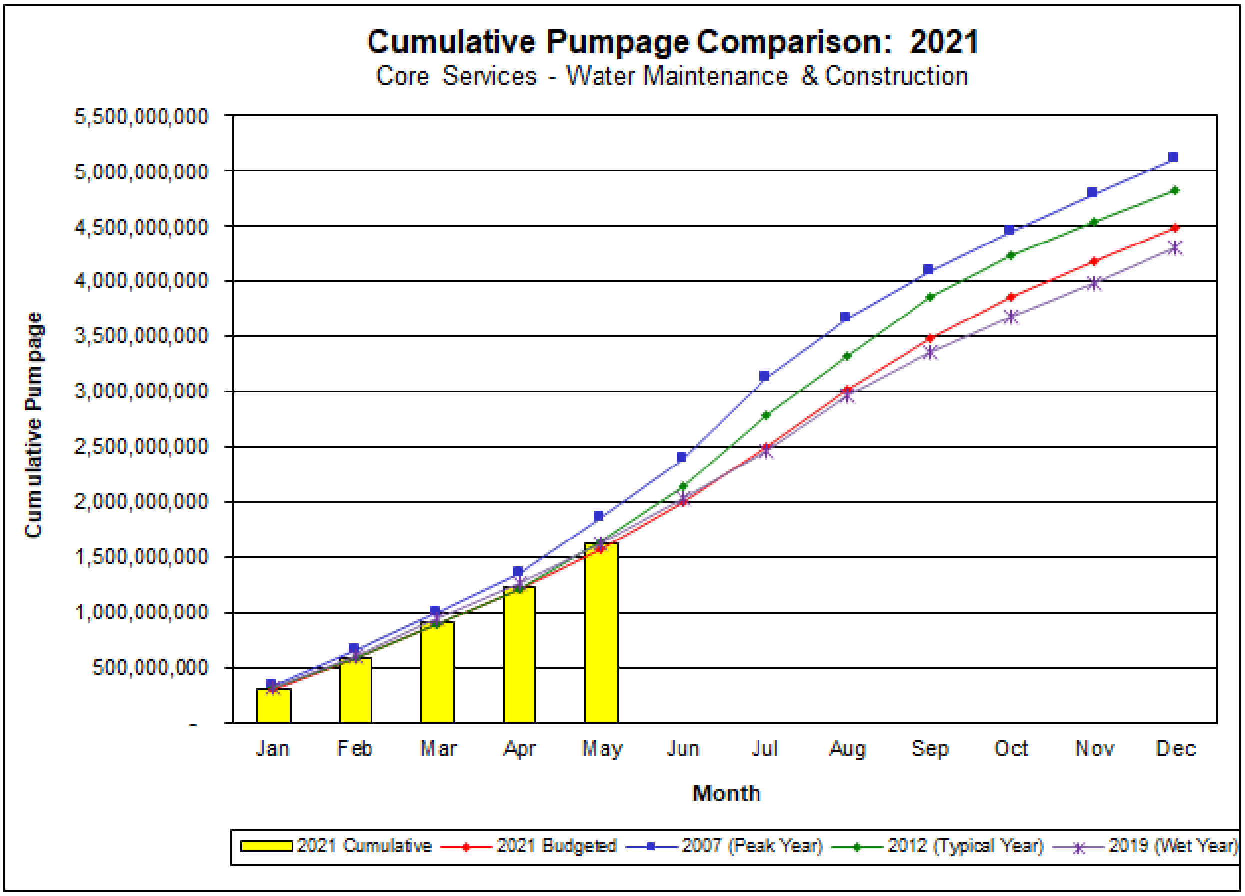
1. **Water Outage Calculations for the month and year to date (May 2021 data):**
   a. Reliability = 99.99937889% Year-to-date Reliability = 99.99898039%
   b. 62 Customers Affected by Outages Year-to-date Customers Affected by Outages = 559
   c. 190.3 Customer Outage Hours Year-to-date Customer Outage Hours = 1521.7
   d. SAIDI = 0.3 Year-to-date SAIDI = 2.2
   e. CAIDI = 184.2 Year-to-date CAIDI = 163.3

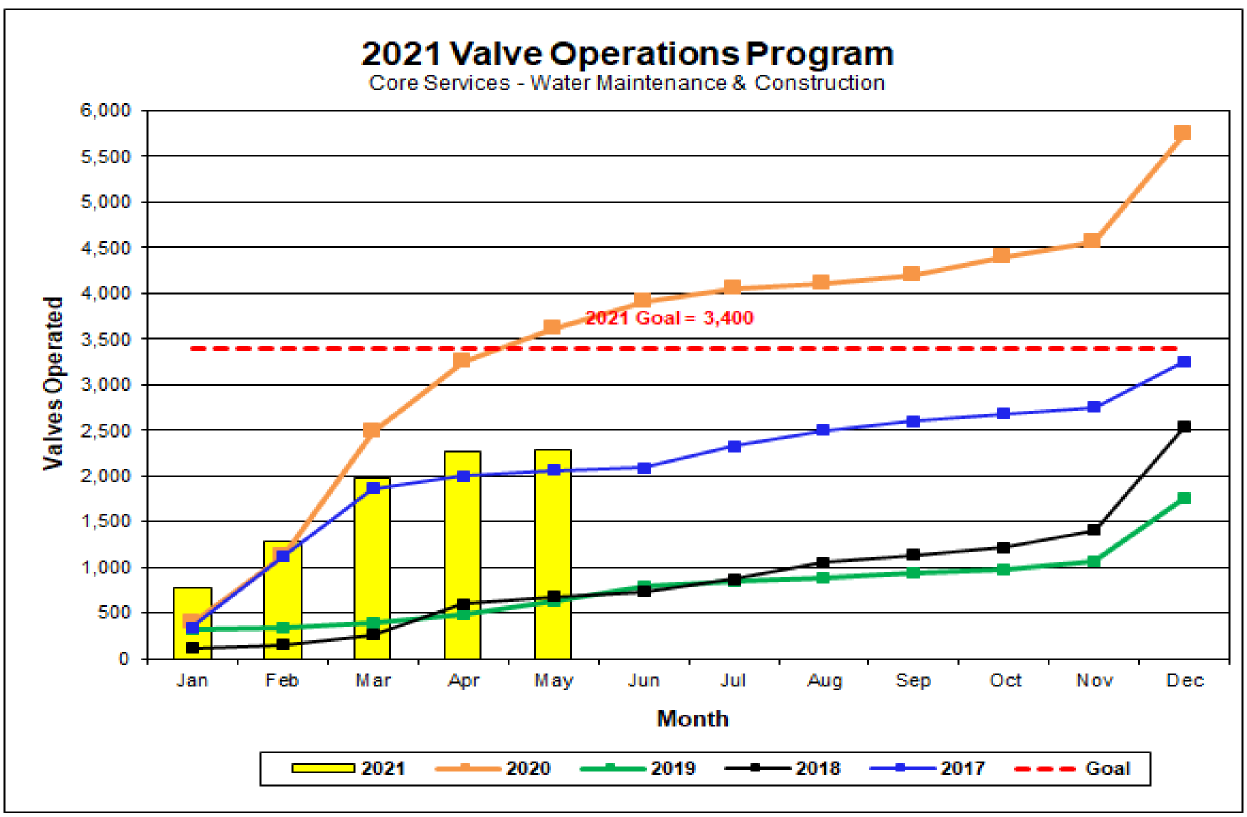
- Performed 2,379 Gopher State water utility locates during the month for a total of 7,203 for the year.
- Repaired water distribution system failures or maintenance at the following locations during the month:
  - 15th Ave & 4th St NE – (leak) – 5/4
  - 11th Ave NE – (joint) – 5/11

- 4111 5th Pl NW – (main break) – 5/23

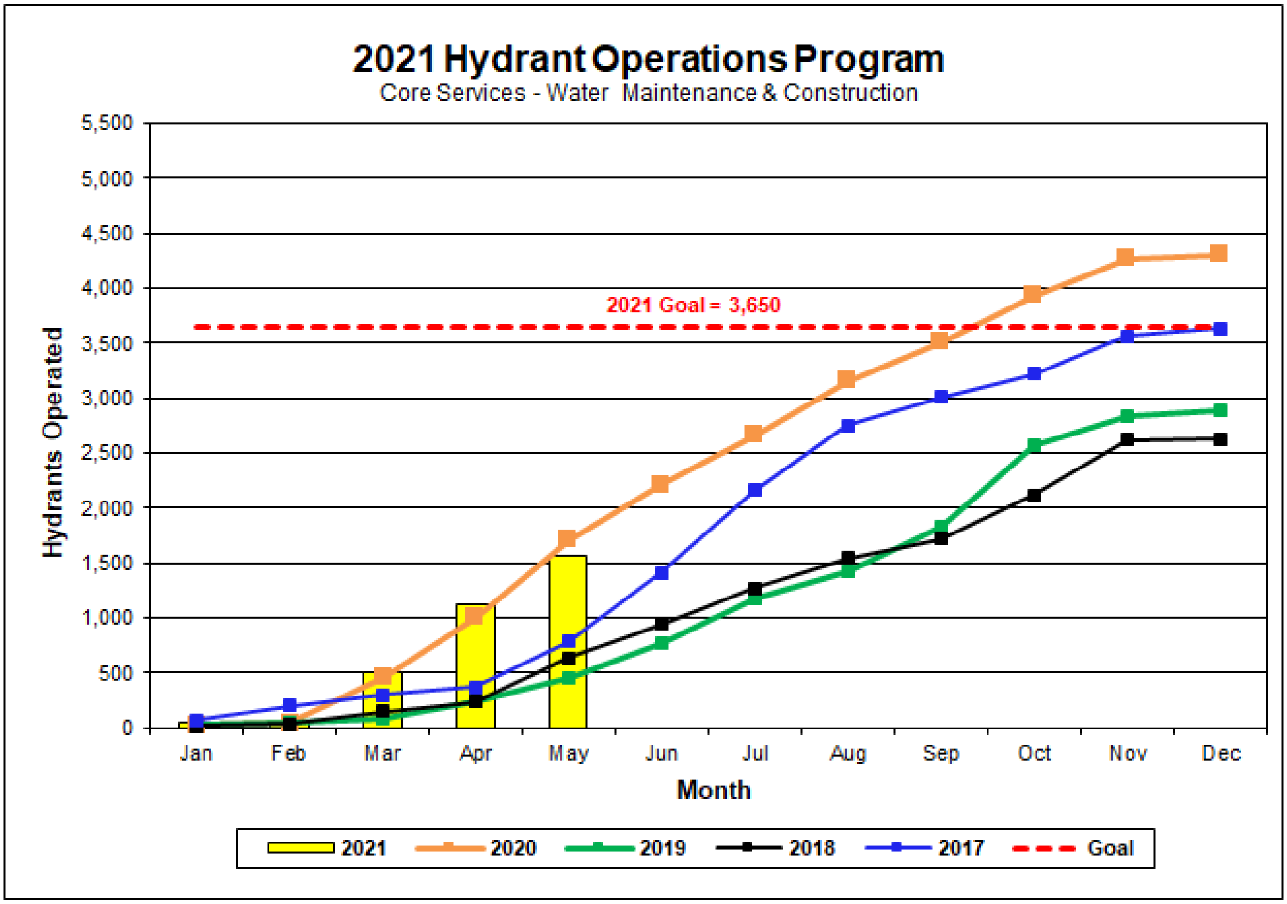
- RPU personnel received 62 inquiries during the month by phone, email, and in person related to questions about letters that customers received regarding how to accomplish backflow testing and backflow prevention.







Attachment: Division Reports June 2021 (13522 : Division Reports & Metrics - June 2021)



GIS/Property Rights

- Hydro line LIDAR flight completed utilizing drone technology. Deliverables will include a 3D point cloud of the corridor and also identify vegetation and other clearance issues that need to be addressed.

SAFETY / COMPLIANCE & PUBLIC AFFAIRS
June 2021

1. **Safety**

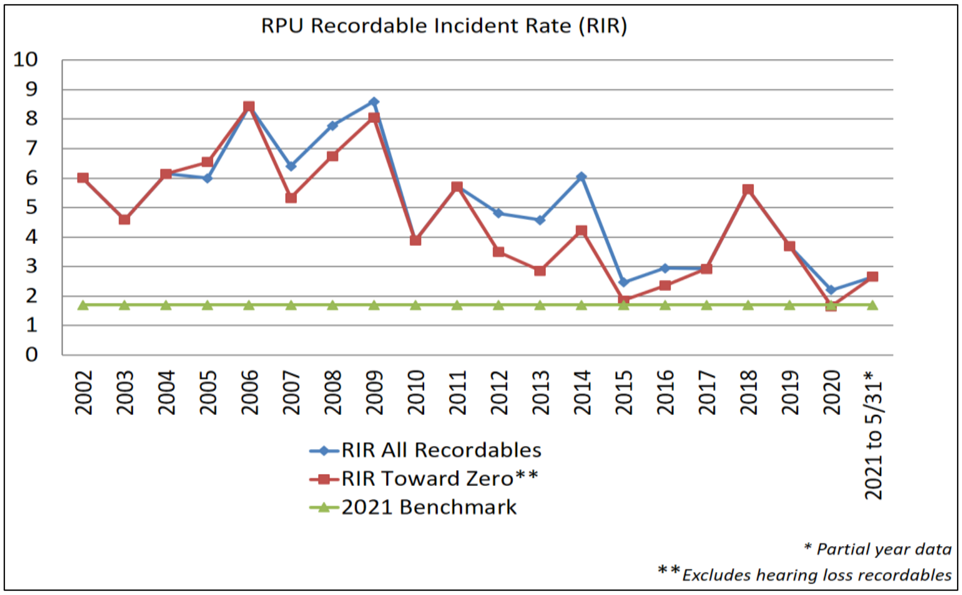
TRAINING	Total Required Enrollments	Completions as of 5/31/2021	Percent Complete
May 2021	568	562	98.9%
Calendar Year to 5/31/2021	3124	3118	99.8%

SAFETY TEAMS	Total Members	Members Attending	Percent Attending
May 2021	25	22	88.0%
Calendar Year to 5/31/2021	177	150	88.2%

INCIDENTS	Reports Submitted	OSHA Cases[1]	RPU RIR[2]	BLS RIR[3]
May 2021	5	0	--	--
Calendar Year to 5/31/2021	14	2	2.7	1.7

1	Deemed to meet OSHA criteria as a recordable case by RPU Safety Manager, subject to change
2	Recordable Incident Rate – Number of OSHA Recordable Cases per 100 employees.
3	Bureau of Labor Statistics nonfatal illnesses and injuries in the utility sector

22 of RPU's 24 departments are recordable injury free in 2021
212 of RPU's 214 employees are recordable injury free in 2021



2021 OSHA Recordable Case Detail				
Work Area	**Incident Date**	**Description**	**Primary Reason it's a Recordable**	**Corrective Action**
T&D	2/8/2021	Slipped on ice in parking lot striking head and shoulder (R) on pavement	Restricted Work	Reviewed salting/sanding procedures
Water	3/1/2021	Possible knee (L) injury due to slip on ice	Days Away	Encouraged use of better slip resistant footwear

SAFETY INITIATIVES

1. New worker safety orientations provided to seasonal staff starting work this month. This included setting up these workers up in Aspire (Learning Management System) and training them how to use this system.
2. Pre job safety discussions were conducted with site preparation contractor for new Marion Road Substation. This included completion of the RPU Contractor Safety Project Management Form.
3. Developed schedule and Field Performance Requirements Checklists for annual line workers skills training to be conducted in June.

2. <u>Environmental & Regulatory Affairs</u>

- On June 7th samples were collected at all 31 wells to have them analyzed for general chemistry, anions and bacteria. RPU's wells are part of Olmsted County's Long-Term

Groundwater Monitoring Network, which started in 1990. RPU secured a grant from MN Dept. of Health for $7,500 to cover the cost of the testing.

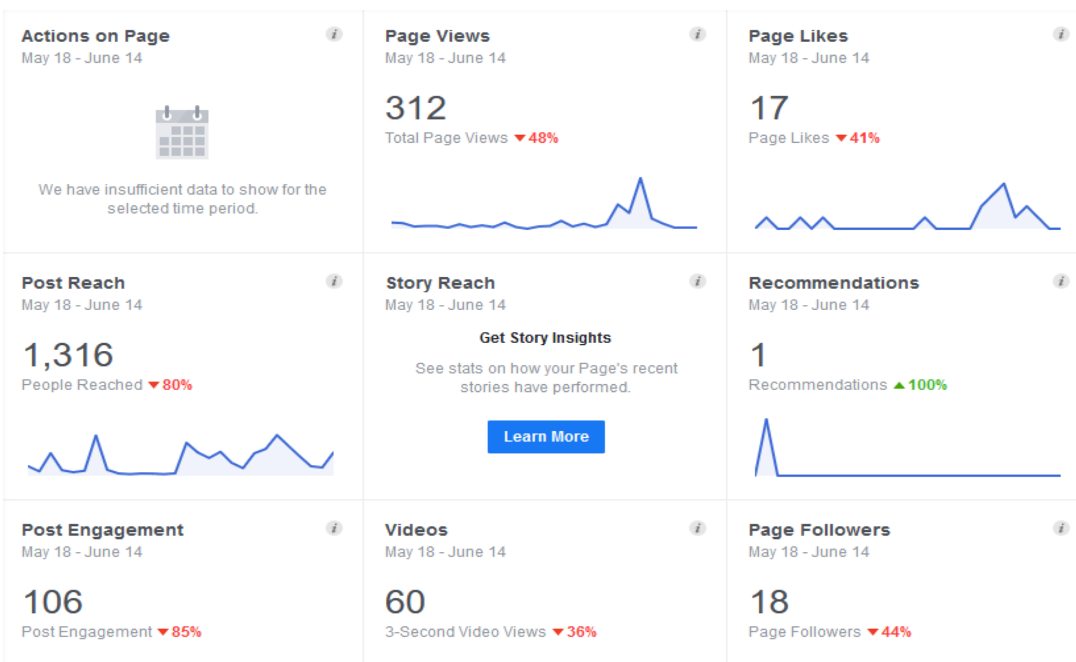
- On June 17th samples were collected at all wells to be analyzed for PFAS compounds. Per- and polyfluoroalkyl substances (PFAS) are a group of man-made chemicals that includes PFOS. PFAS have been manufactured and used in a variety of industries around the globe, including in the United States since the 1940s. Most commonly used in fire-fighting foam in our area. To date PFAS have not been detected in RPU's water supply. MDH has set new health based values in the parts per trillion.

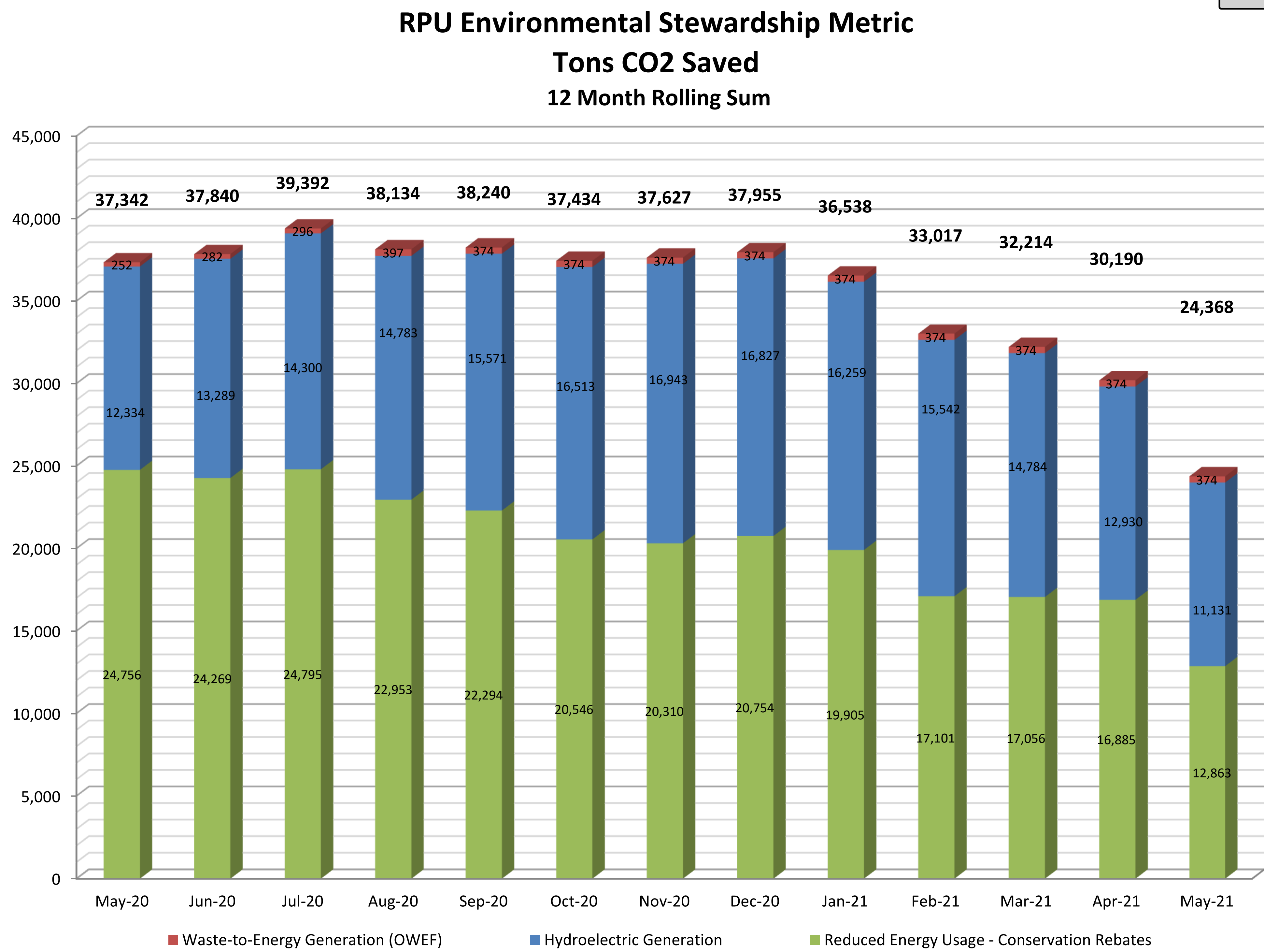
3. Communications

- Staff met with the local media regularly during the stretch of warm, humid days this month. We provided the media with energy conservation tips, ways to stay cool without turning the AC up and reminded them that RPU did not have a rate increase in 2021.

- RPU was a media sponsor of the Rochesterfest Parade presentation on KAAL and we had a bucket truck in the parade on Saturday, June 26th.

- RPU was featured in a MN Department of Health news release focused on planning that prevented pandemic problems for public water suppliers in Minnesota. Doug Klamerus was quoted in the news release from June 3rd, 2021.





RPU Environmental Stewardship Metric
Tons CO2 Saved
12 Month Rolling Sum
45,000
40,000
35,000
30,000
25,000
20,000
15,000
10,000
5,000
0
37,342
37,840
39,392
38,134
38,240
37,434
37,627
37,955
36,538
33,017
32,214
30,190
24,368
252
282
296
397
374
374
374
374
374
374
374
374
374
12,334
13,289
14,300
14,783
15,571
16,513
16,943
16,827
16,259
15,542
14,784
12,930
11,131
24,756
24,269
24,795
22,953
22,294
20,546
20,310
20,754
19,905
17,101
17,056
16,885
12,863
May-20
Jun-20
Jul-20
Aug-20
Sep-20
Oct-20
Nov-20
Dec-20
Jan-21
Feb-21
Mar-21
Apr-21
May-21
Waste-to-Energy Generation (OWEF)
Hydroelectric Generation
Reduced Energy Usage - Conservation Rebates

POWER RESOURCES MANAGEMENT

JUNE 2021

Portfolio Optimization

1. In May, RPU continued to bid GT1, GT2 and WES into the MISO day-ahead and real-time markets. Only GT2 and WES are capable of participating in the ancillary services market.

   a. Ancillary Service Market – Supplemental Reserves
      i. Cleared DA
         1. GT2 – 31 days
         2. WES – 18 days
      ii. Deployment YTD
         1. GT2 – 1
         2. WES – 1

   b. Dispatched by MISO
      i. GT1 – 4 times YTD 14
      ii. GT2 – 6 times YTD 35
      iii. WES – 10 times YTD 37

   c. Hours of Operation
      i. GT1 – 30 hours YTD 85 hours
      ii. GT2 – 38 hours YTD 244 hours
      iii. WES – 67 hours YTD 243 hours

   d. Electricity Generated
      i. GT1 – 710 MWh YTD 1,817 MWh
      ii. GT2 – 1,392 MWh YTD 7,810 MWh
      iii. WES – 2,162 MWh YTD 7,949 MWh

   e. Forced Outage
      i. GT1 – 96 hours YTD 206 hours
      ii. GT2 – 3 hours YTD 3 hours
      iii. WES – 0 hours YTD 168 hours

2. MISO market Real Time Price averaged $18.95/MWh and Day Ahead Price averaged $16.26/MWh. These values are three to four times higher than January averages.

Customer Relations

(Contact Center and Marketing, Commercial and Residential)

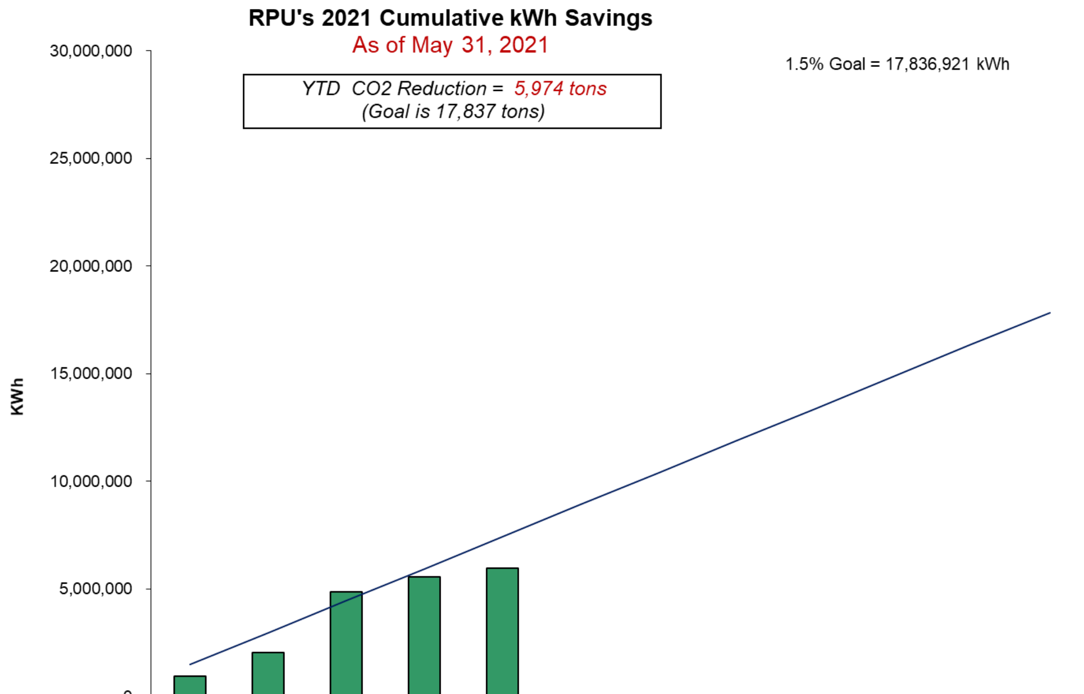
Stakeholder Engagement, Forums, and Meetings

1. On June 3, the marketing team participated in the annual Rochester Area Builders Association golf outing. We sponsored green thirteen and set-up a table to talk with local vendors, contractors, and customers.
2. On June 10, commercial marketing staff participated in counter days at Viking Electric to talk with vendors and contractors about our programs.
3. On June 17, the marketing team attended a webinar hosted by the Midwest Chapter of the Association of Energy Service Professionals (AESP). The MN Department of Commerce presented on the roll out of the new EcoAct legislation and the implementation timelines.
4. On June 23, commercial marketing staff participated in counter days at Dakota Supply Group to talk with vendors and contractors about our programs.
5. The Director of Customer Relations presented on RPU's focused outreach efforts, customer segmentation analysis and 2020 work on Coronavirus Relief Funds grants at the Annual APPA conference.

Opportunities for Customers

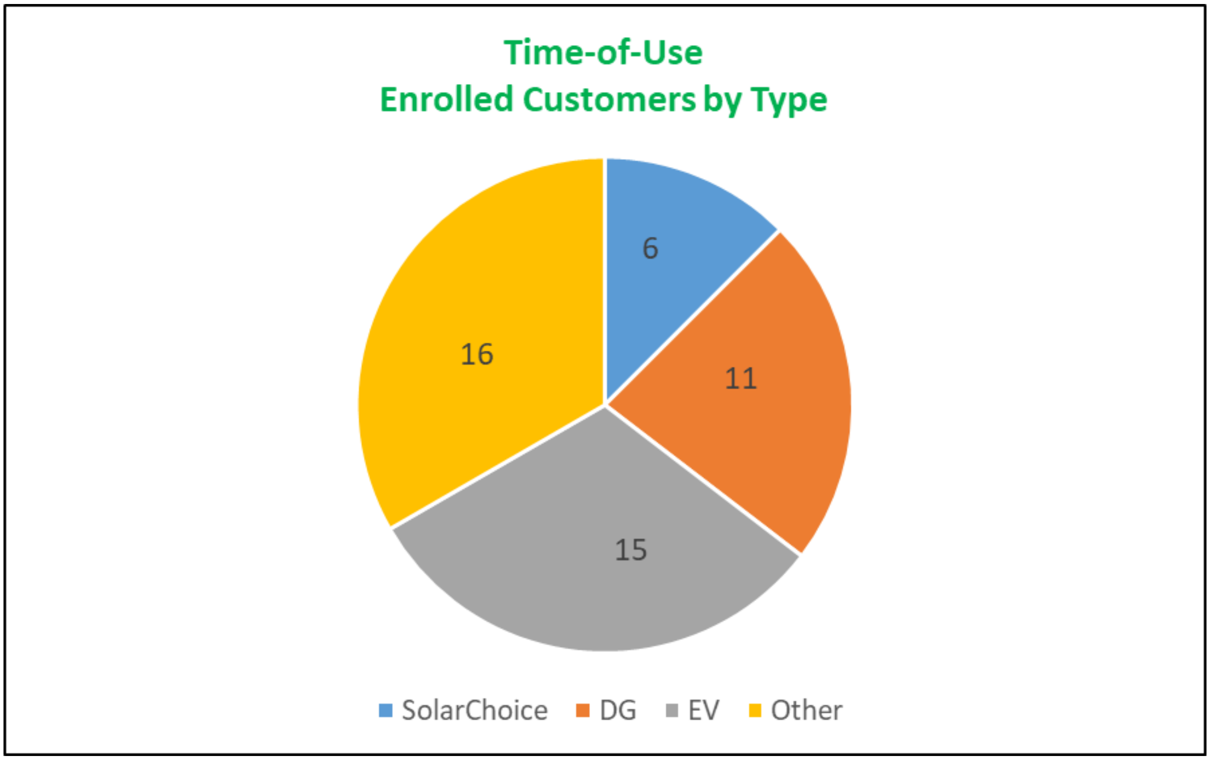
1. As of June 17, Customer Care made outreach calls to 1,603 landlords to inform them of the *RentHelpMN* resource program, available for eligible tenants. Customer Relations leadership continues to seek out as much information and guidance on the mortgage assistance program that is slated to roll out from the state.
2. The Director of Customer Relations joined a planning group led by the county called Welcome Week which held its first meeting. The group will be developing outreach plans to welcome new citizens and new members of the community in September. In working with the City's new Diversity, Equity and Inclusion Director, Chao Mwatala on a resource fair concept, RPU will work on having a booth on reading utility bills and ways to conserve.
3. Return to normal operations resumes Monday, August 2. In preparation, we are continuing outreach efforts to customers that may be impacted by disconnects for non-payment. Communications will be sent via postcards, phone calls and outreach letters to customers with delinquent balances. Postcards will be printed in three languages. Customer Relations will continue to encourage and inform

our customers of available resources within the community, as well as offer payment arrangements.

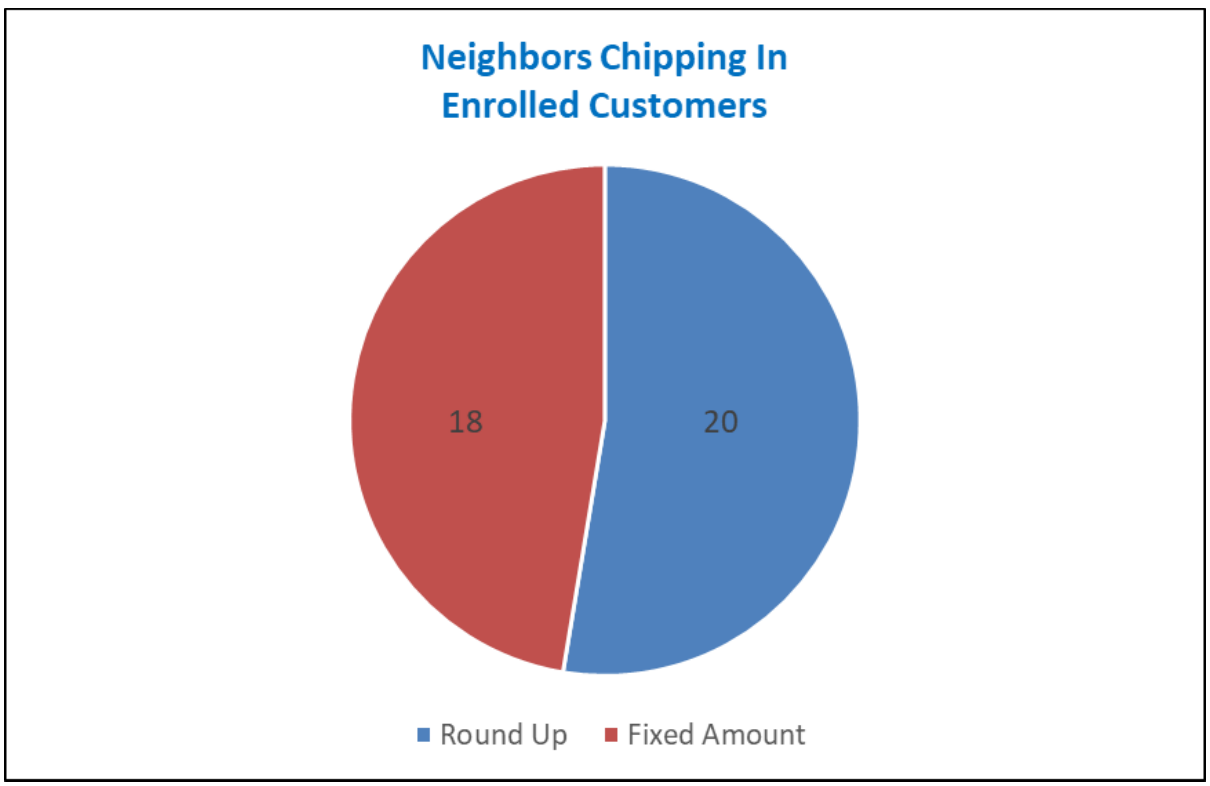


	Jan	Feb	March	April	May	June	July	Aug	Sept	Oct	Nov	Dec
YTD Actual kWh Savings	935,146	2,048,833	4,859,561	5,552,344	5,974,164	0	0	0	0	0	0	0
% to Goal	5.2%	11.5%	27.2%	31.1%	33.5%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
1.5 percent	1,486,410	2,972,820	4,459,230	5,945,640	7,432,050	8,918,461	10,404,87	11,891,28	13,377,69	14,864,10	16,350,51	17,836,92

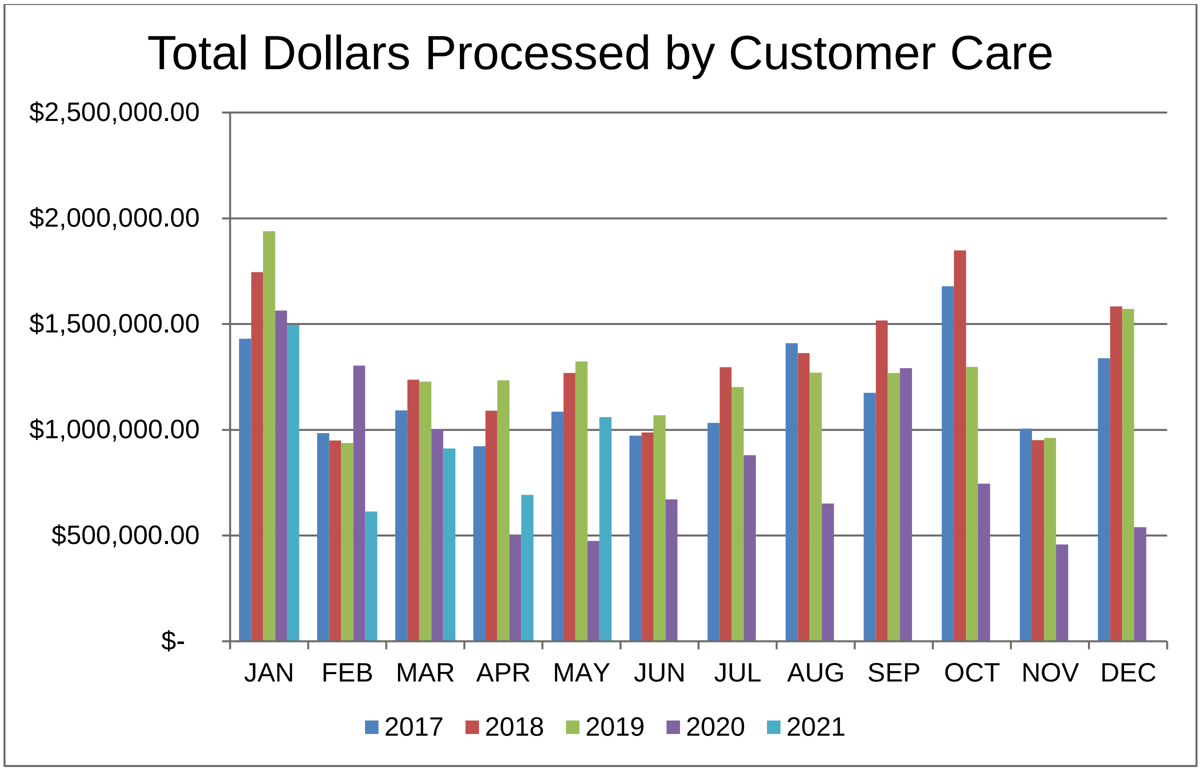
- Avoided kW: 859 kW
- Cost of Avoided kW: $896/kW



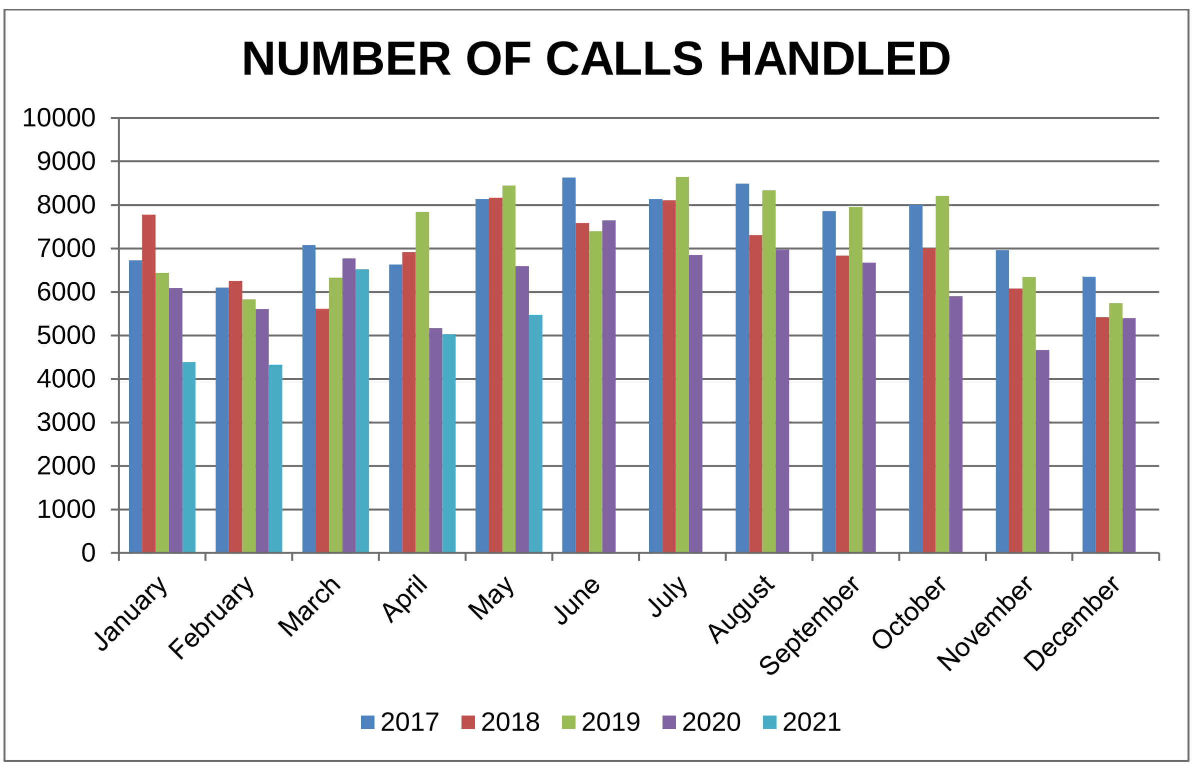
- Total Customers Enrolled: 48



- Total Customers Enrolled: 38



- Total Number in Dollars Processed by Representatives: $1,059,765 (graphed above)
- Total Number of Transactions Processed by Representatives: 2,920

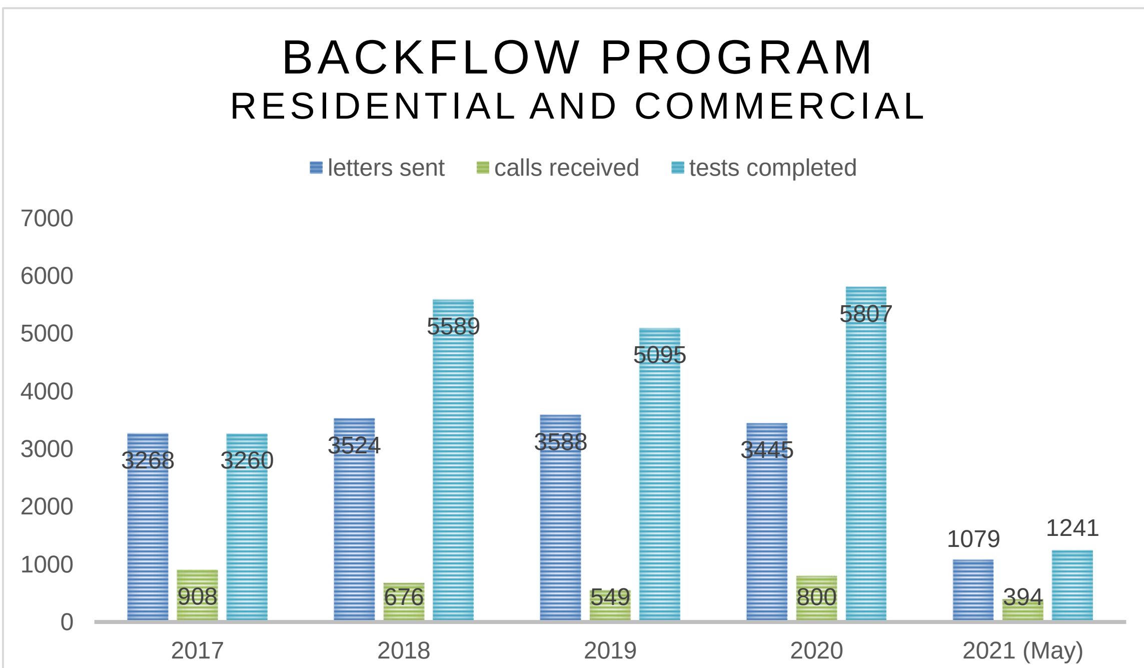


- Total Number of Calls: 5,478 (graphed above)

Corporate Services

Business Services:

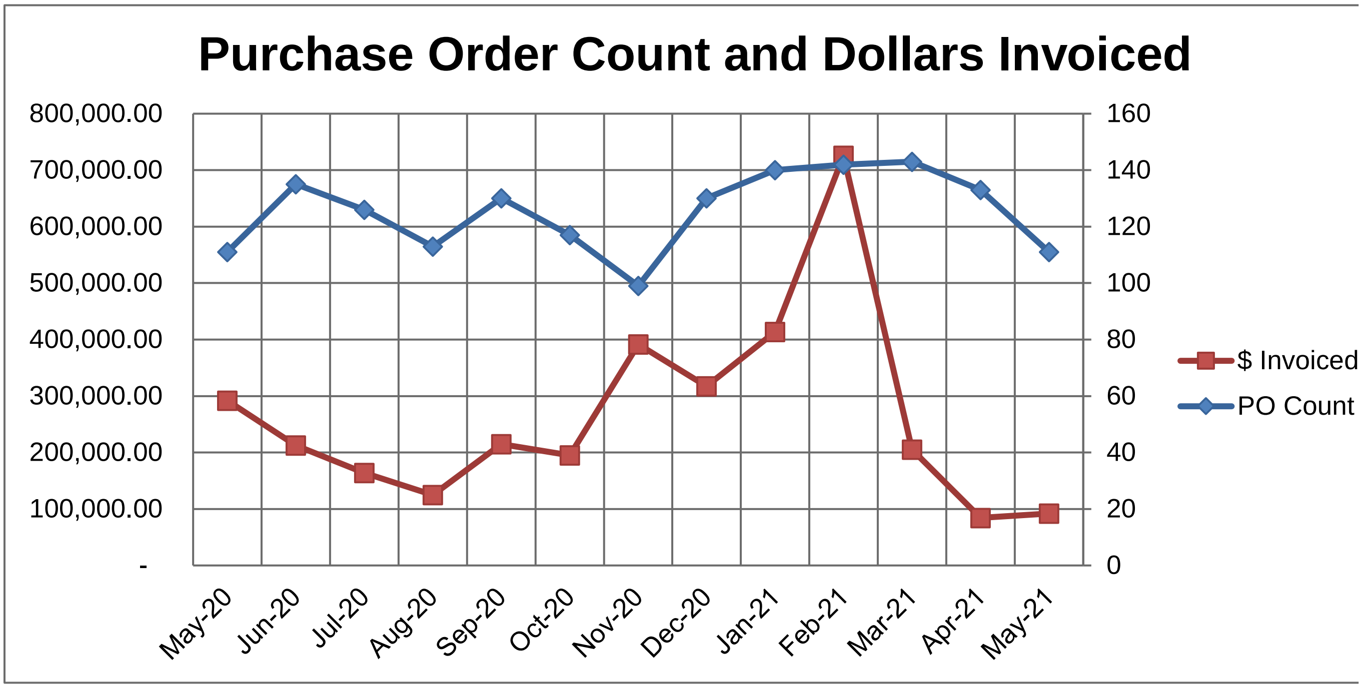
- Payroll/HR – Coordinated the on boarding of three full time employees and five seasonal positions.
- Payroll/HR – Assisted employees with vaccination record submission process.
- Payment Drop Boxes – discontinued payment drop boxes at 3 HyVee locations and the Government Center due to low use. Retained the payment drop boxes at the Service Center and Silver Lake Plant.
- Administrative – Updated masking protocol signs for the lobby and internal office personnel.
- As part of the customer outreach efforts, 6,465 customer letters were printed and mailed internally including 3,816 outreach letters and 1,414 notifications for planned work.
- Water Ops Back Flow

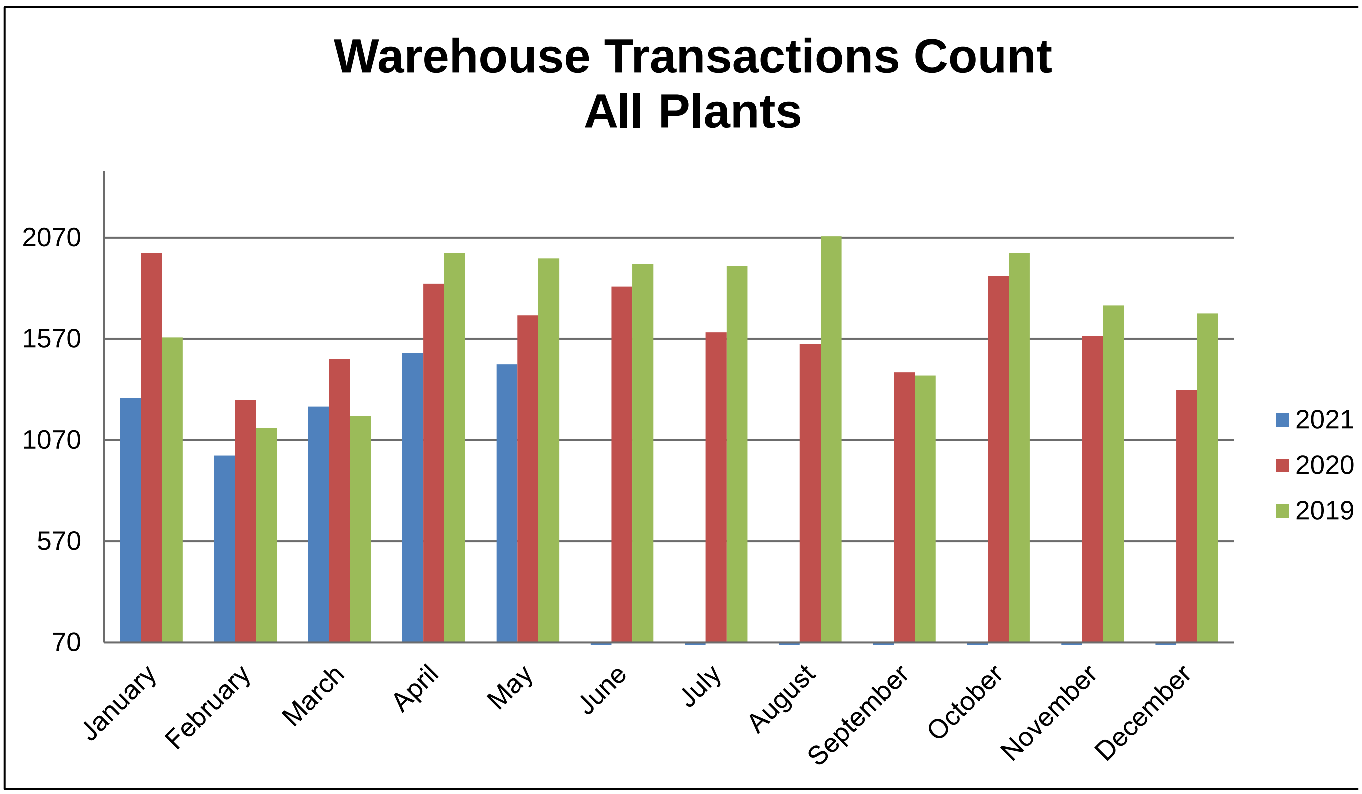


Purchasing and Materials Management:

1. Building materials costs continue to escalate to the point where vendors are moving to cost plus agreements, which shifts the risk of material price increases to the utility. The utility may need to reduce how long a bid price is guaranteed from 90 days currently to 30 days in order to have vendors submit bids.
2. Lead times on cable is now up to 18 weeks. RPU will be ordering 2022 cable supplies early to ensure delivery before the 2022 construction period.

Note: Feb 2021 Dollars Invoiced increase is due to $332,852 for fuel oil to run GT2 during the cold weather incident in February.

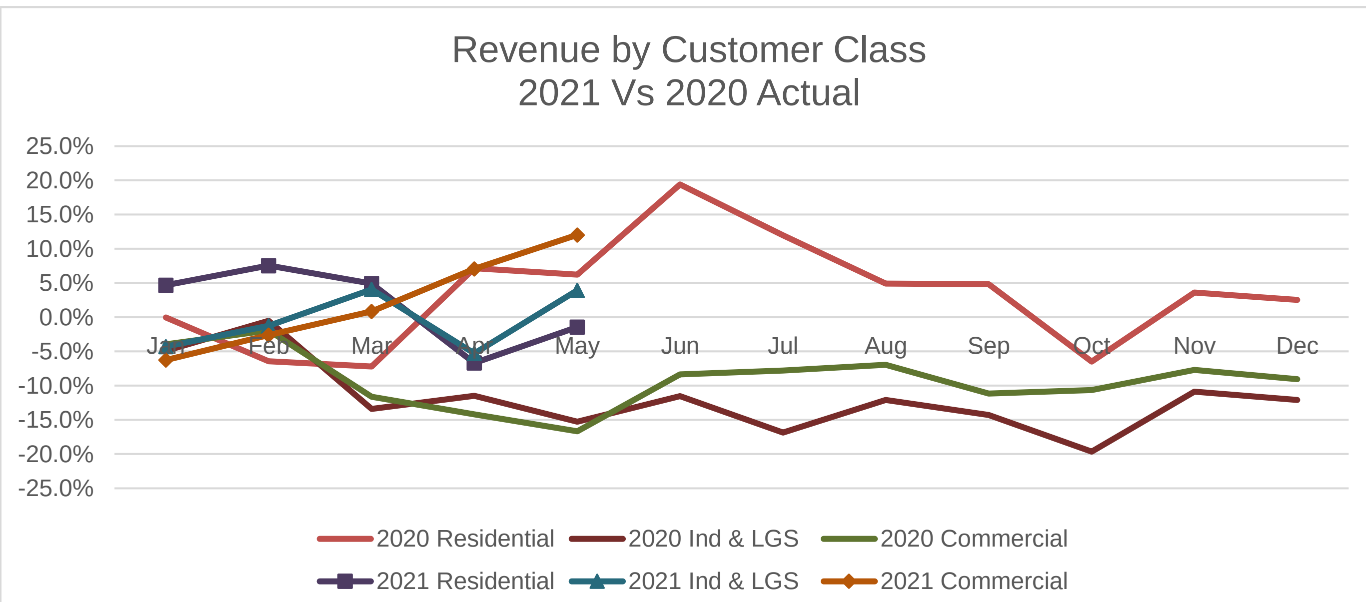




Finance and Accounting:

- Julie Ackerman, Financial Controller, has resigned her position effective July 6, 2021. We will be reposting this position.

- The 2022 budget will be reviewed with the Finance Committee and the Board in August. The RPU budget will be reviewed by the Council during a study session in September, with approvals requested of the RPU Board and Council in October and December, respectively. Managers are working on their cost center budget and staffing requests for 2022 currently.
- Return to Normal Operations – Customer Relations, Finance & Collections, Metering and the IT team are working to reconfigure the current customer notifications, the internal tracking and reporting process to accommodate the new payment terms, deposit policy and notification processes which were approved by the Board in May. Outreach calls to customers that are likely to show up on disconnect lists starting in August will be contacted during July to set up payment arrangements. This is a significant effort. The requirements are continuing to change as the State is working to implement additional assistance programs.
- Bond Payments – Semi-annual bond interest payments were made on May 31, 2021 totaling $3,311,777.
- Covid19 Financial Impacts – As part of our 2021 Electric Utility budget process, sales volumes and gross margin were adjusted down. The 2021budget anticipates a slow recovery during 2021. The Electric Utility gross margin for May 2021 is over budget by $229,132 or 5.7%. This is $235,870 or 5.9% above May 2020 actual gross margin.



- Accounts Receivable – Past due account balances have increased from $1,348,197 at the end of February 2020, before the pandemic, to $3,048,946 as of May 31, 2021. Of this amount, $1,914,671 is due from residential customers and $1,134,275 is due from commercial accounts. RPU will continue to reach out to customers to get them connected to assistance that they may be qualified for.

Description	Residential			Commercial (Non Residential)		
	02/29/2020	5/31/2021	Incr (Decr)	02/29/2020	5/31/2021	Incr (Decr)
% Current	92.0%	67.9%	-24.1%	94.6%	73.9%	-20.7%
% Past Due	17.5%	32.1%	14.6%	5.8%	26.1%	20.3%
Amount Past Due	$ 968,491	$ 1,914,671	$ 946,180	$ 379,705	$ 1,134,275	$ 754,570
# Customers Past Due	6,349	4,985	(1,364)	385	433	48
Average Balance Past Due	$ 153	$ 384	$ 232	$ 986	$ 2,620	$ 1,634
# Customers > $1,500 Past Due	17	322	305	38	74	36
# Customers > $5,000 Past Due	-	10	10	13	30	17

Information Technology:

- The cutover to the new SCADA controls system took place in May. This project is on schedule to be completed by the end of June.
- IT Security – Started a project to enhance our real-time monitoring and response to system intrusions.

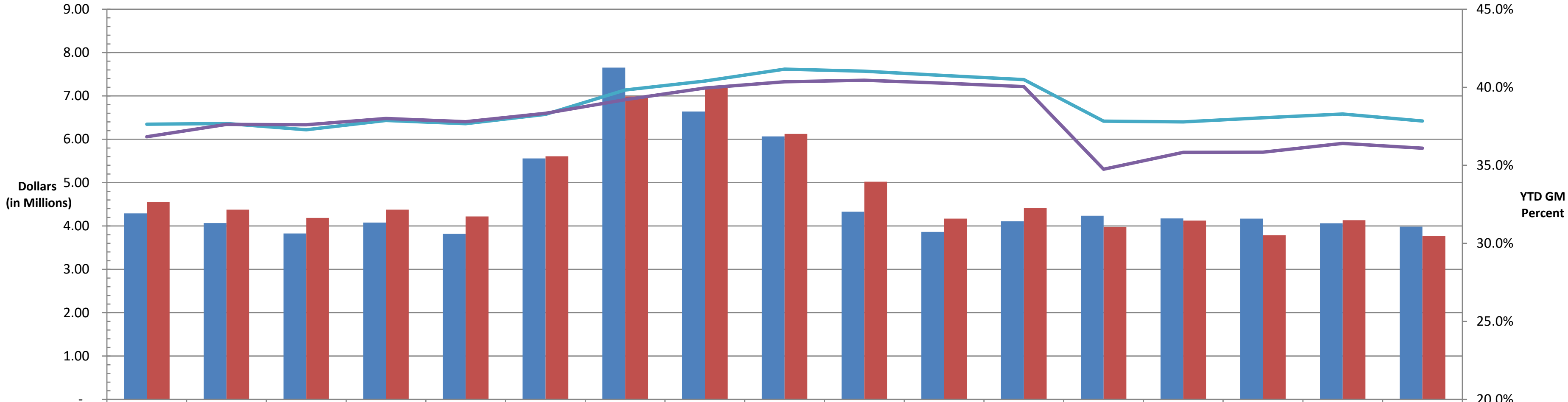
Financial Results:

Note: Budget numbers are compared to the approved 2021 budget and have been adjusted for 2020 approved project budgets carried over to 2021.

The large variance in the Electric Utility Change in Net Position for May is due to budgeted contributions in aid of construction related to the Marion Road Substation and 10MW solar installation being behind compared to the budget timing.

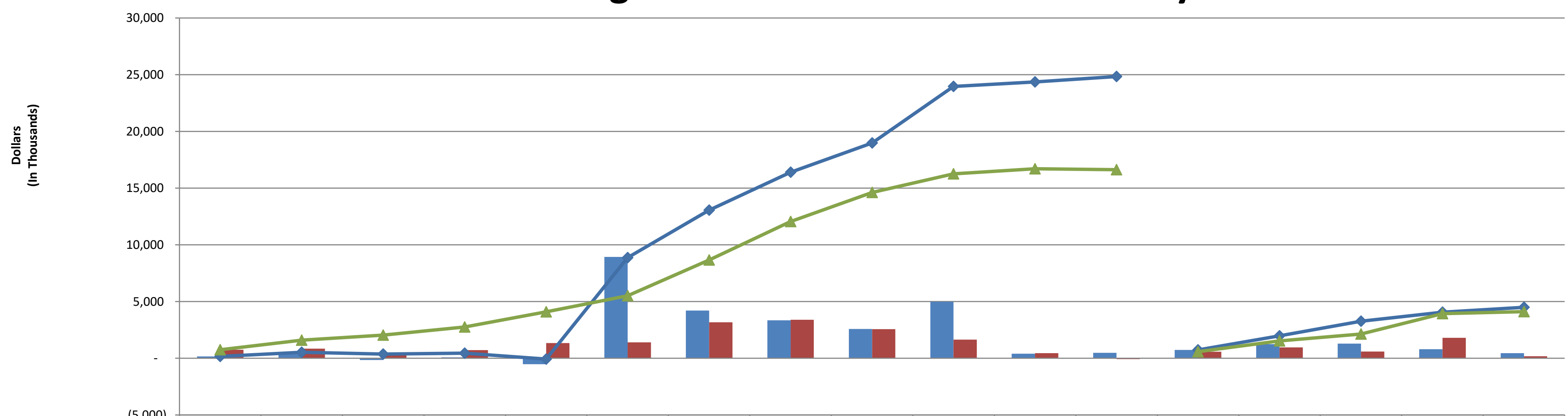
	Current Month			Year to Date		
(In Thousands)	Actual	Budget	Variance	Actual	Budget	Variance
Revenue - Electric	$ 11,697	$ 11,462	$ 235	$ 59,341	$ 57,890	$ 1,451
Revenue - Water	926	908	18	4,133	4,212	(79)
Change in Net Position - Electric	440	177	263	4,497	4,113	384
Change in Net Position - Water	180	90	90	420	374	46

2020 - 2021 Retail Gross Margin - Electric Utility



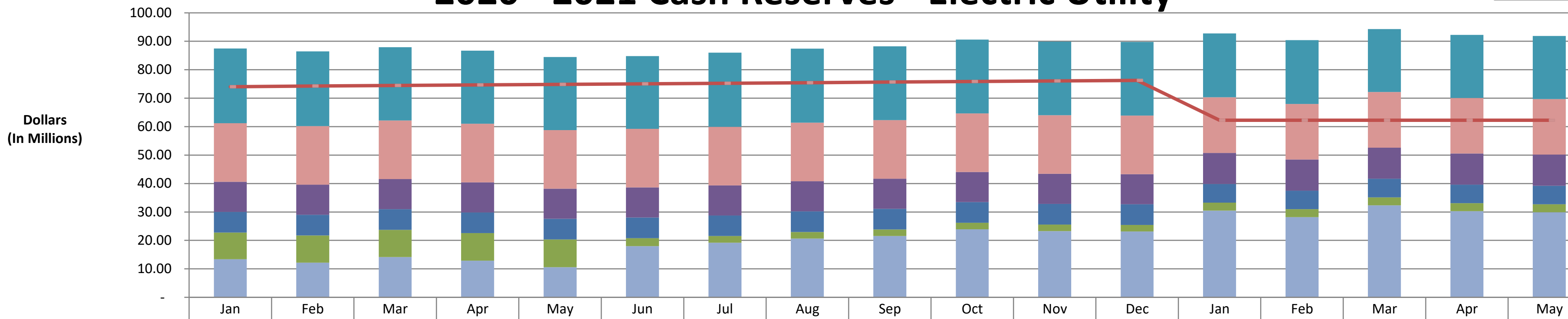
	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY
GM - Actual	4.29	4.07	3.83	4.08	3.82	5.56	7.65	6.64	6.07	4.33	3.86	4.11	4.24	4.17	4.17	4.06	3.98
GM - Budget	4.55	4.38	4.19	4.38	4.22	5.61	6.99	7.18	6.12	5.02	4.17	4.41	3.98	4.13	3.79	4.13	3.77
GM % YTD - Actual	37.6%	37.7%	37.3%	37.9%	37.7%	38.3%	39.8%	40.4%	41.2%	41.0%	40.7%	40.5%	37.8%	37.8%	38.1%	38.3%	37.8%
GM % YTD - Budget	36.8%	37.6%	37.6%	38.0%	37.8%	38.3%	39.2%	40.0%	40.4%	40.4%	40.3%	40.0%	34.7%	35.8%	35.8%	36.4%	36.1%

2020 - 2021 Change in Net Position - Electric Utility



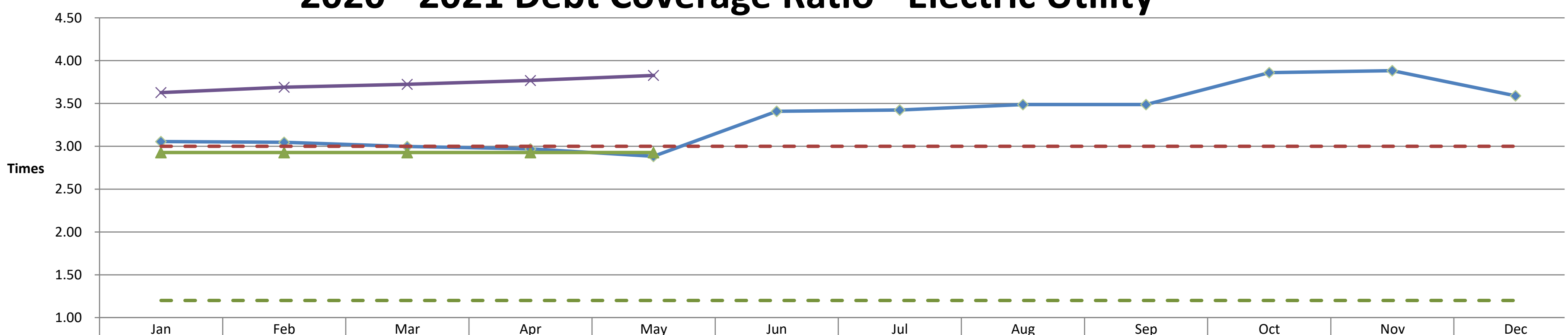
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May
Chg Net Position - Actual	158	371	(158)	81	(525)	8,935	4,201	3,338	2,582	4,979	396	481	731	1,238	1,292	796	440
Chg Net Position - Budget	747	853	441	715	1,344	1,404	3,163	3,387	2,559	1,648	447	(75)	579	955	597	1,805	177
Net Position - YTD Actual	158	529	371	452	(72)	8,862	13,063	16,401	18,984	23,963	24,359	24,839	731	1,969	3,261	4,057	4,497
Net Position - YTD Budget	747	1,600	2,041	2,755	4,099	5,503	8,666	12,053	14,612	16,260	16,707	16,632	579	1,534	2,131	3,936	4,113

2020 - 2021 Cash Reserves - Electric Utility



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May
Capital & Major Maint	26.23	26.23	25.73	25.71	25.69	25.58	26.04	26.02	25.96	25.95	25.91	25.85	22.45	22.42	22.15	22.17	22.17
Working Funds	20.59	20.59	20.59	20.59	20.59	20.59	20.59	20.59	20.59	20.59	20.59	20.59	19.54	19.54	19.54	19.54	19.54
Contingency	10.58	10.58	10.58	10.58	10.58	10.58	10.58	10.58	10.58	10.58	10.58	10.58	10.94	10.94	10.94	10.94	10.94
Clean Air Rider	7.26	7.26	7.26	7.26	7.26	7.26	7.26	7.26	7.26	7.26	7.26	7.26	6.53	6.53	6.53	6.53	6.53
Spl Cap & Maj Maint	9.39	9.59	9.60	9.70	9.79	2.77	2.30	2.30	2.30	2.30	2.30	2.30	2.80	2.80	2.80	2.80	2.80
Unreserved Cash	13.41	12.18	14.16	12.86	10.59	18.00	19.23	20.65	21.54	23.93	23.26	23.17	30.51	28.19	32.36	30.29	29.90
Total (Excluding Debt Service)	87.47	86.43	87.92	86.71	84.50	84.79	86.00	87.40	88.24	90.62	89.90	89.75	92.77	90.42	94.32	92.27	91.88
Min Reserve (Policy - Ex Debt Service)	74.06	74.26	74.46	74.66	74.86	75.06	75.26	75.46	75.66	75.86	76.06	76.26	62.26	62.26	62.26	62.26	62.26

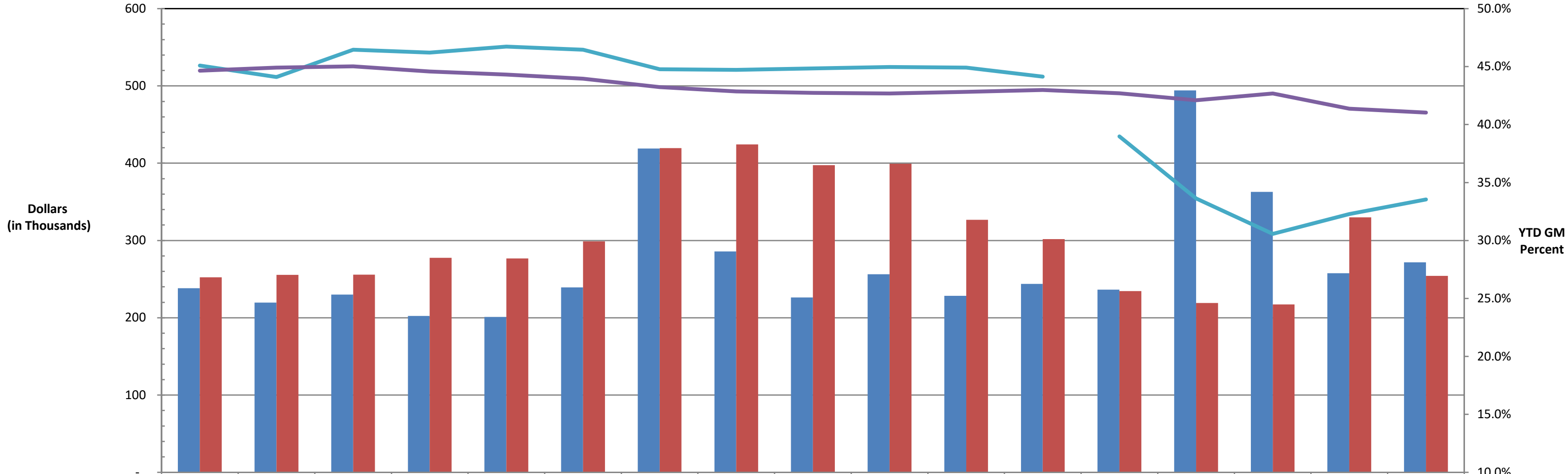
2020 - 2021 Debt Coverage Ratio - Electric Utility



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2020 Actual	3.06	3.05	3.00	2.97	2.88	3.41	3.42	3.49	3.49	3.86	3.88	3.59
2021 Budget	2.93	2.93	2.93	2.93	2.93							
2021 Actual	3.63	3.69	3.72	3.77	3.83							
Rating Goal	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00
Bond Covernant	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20

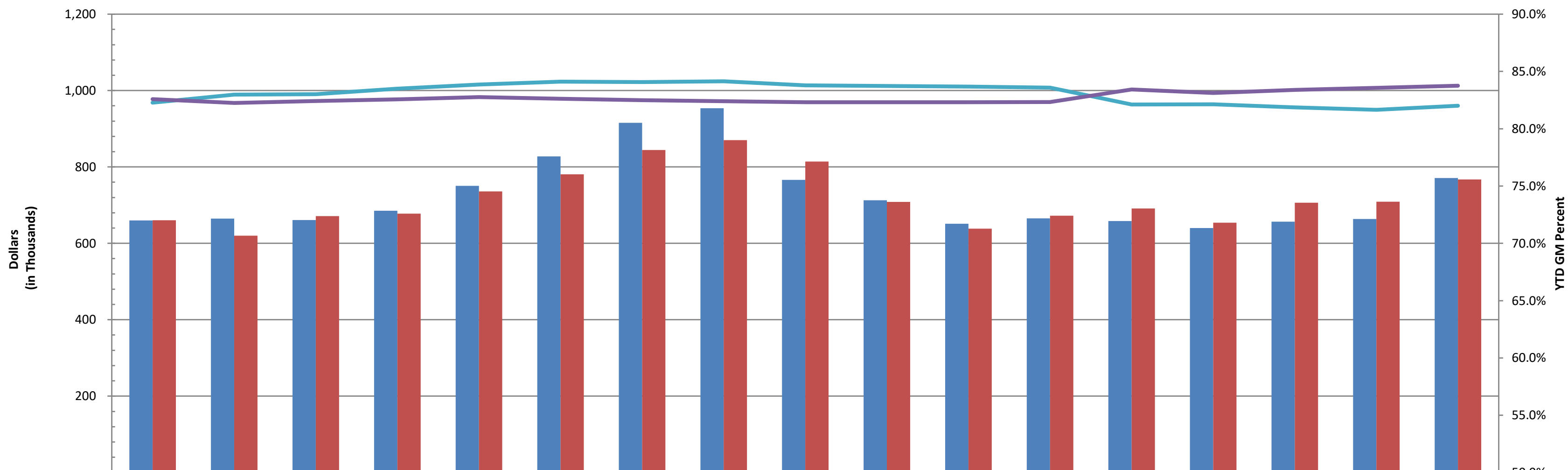
Month

2020 - 2021 Gross Margin - Steam/Wholesale Electric



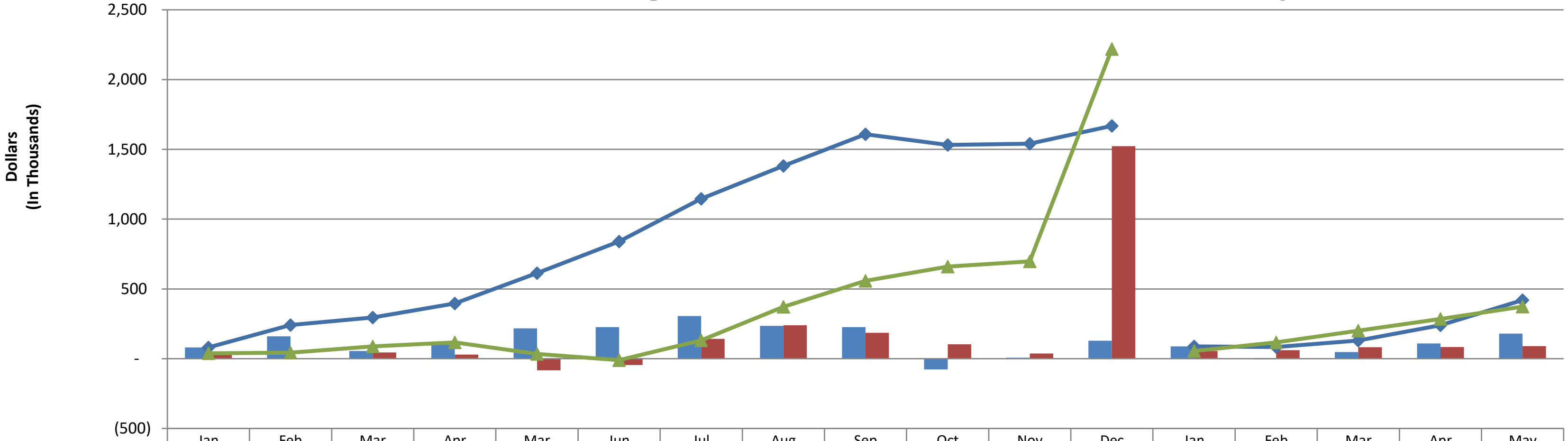
	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY
Gross Margin - Actual	238	220	230	202	201	239	419	286	226	256	228	244	236	494	363	258	272
Gross Margin - Budget	252	256	256	277	277	299	419	424	397	399	327	302	235	219	217	330	254
Gross Margin % YTD - Actual	45.1%	44.1%	46.5%	46.2%	46.7%	46.5%	44.8%	44.7%	44.8%	45.0%	44.9%	44.1%	39.0%	33.6%	30.6%	32.3%	33.5%
Gross Margin % YTD - Budget	44.6%	44.9%	45.0%	44.6%	44.3%	44.0%	43.2%	42.9%	42.7%	42.7%	42.8%	43.0%	42.7%	42.1%	42.7%	41.4%	41.0%

2020 - 2021 Gross Margin - Water Utility



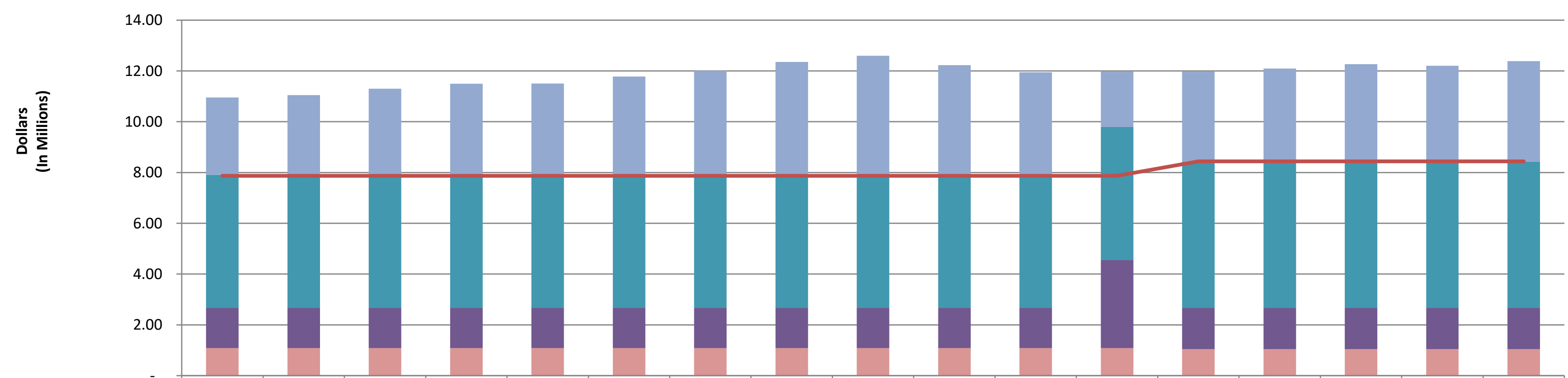
	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY
GM - Actual	660	665	661	685	750	828	916	954	766	713	652	665	658	640	657	664	771
GM - Budget	660	620	671	678	736	781	845	870	814	709	638	672	691	654	706	709	767
GM % YTD - Actual	82.3%	83.0%	83.0%	83.5%	83.9%	84.1%	84.1%	84.1%	83.8%	83.7%	83.7%	83.6%	82.1%	82.1%	81.9%	81.7%	82.0%
GM % YTD - Budget	82.6%	82.3%	82.4%	82.6%	82.8%	82.6%	82.5%	82.4%	82.3%	82.3%	82.3%	82.3%	83.4%	83.1%	83.4%	83.6%	83.8%

2020 - 2021 Change in Net Position - Water Utility



	Jan	Feb	Mar	Apr	Mar	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May
Chg Net Position - Actual	81	161	55	101	218	227	306	235	227	(76)	8	128	88	(5)	48	109	180
Chg Net Position - Budget	39	4	45	30	(82)	(45)	142	240	185	103	37	1,522	55	62	83	84	90
Net Position - YTD Actual	81	241	296	396	614	841	1,147	1,382	1,609	1,533	1,540	1,669	88	83	131	240	420
Net Position - YTD Budget	39	43	87	117	35	(11)	132	372	557	660	697	2,219	55	117	200	284	374

2020 - 2021 Cash Reserves - Water Utility



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May
Unreserved Cash	3.05	3.14	3.39	3.59	3.60	3.87	4.10	4.45	4.69	4.32	4.04	2.18	3.55	3.67	3.83	3.77	3.95
Capital & MM	5.24	5.24	5.24	5.24	5.24	5.24	5.24	5.24	5.24	5.24	5.24	5.24	5.77	5.77	5.77	5.77	5.77
Contingency	1.58	1.58	1.58	1.58	1.58	1.58	1.58	1.58	1.58	1.58	1.58	3.47	1.62	1.62	1.62	1.62	1.62
Working Funds	1.09	1.09	1.09	1.09	1.09	1.09	1.09	1.09	1.09	1.09	1.09	1.09	1.05	1.05	1.05	1.05	1.05
Total	10.96	11.05	11.30	11.49	11.50	11.78	12.01	12.36	12.60	12.23	11.95	11.98	11.98	12.10	12.27	12.21	12.38
Min Reserver (Policy)	7.87	7.87	7.87	7.87	7.87	7.87	7.87	7.87	7.87	7.87	7.87	7.87	8.44	8.44	8.44	8.44	8.44

Attachment: Division Reports June 2021 (13522 : Division Reports & Metrics - June 2021)

we pledge, we deliver

TO: Jeremy Sutton, Director of Power Resources, Fleet & Facilities

FROM: Tina Livingston, Senior Financial Analyst

SUBJECT: LOAD FORECAST SUMMARY FOR 2021

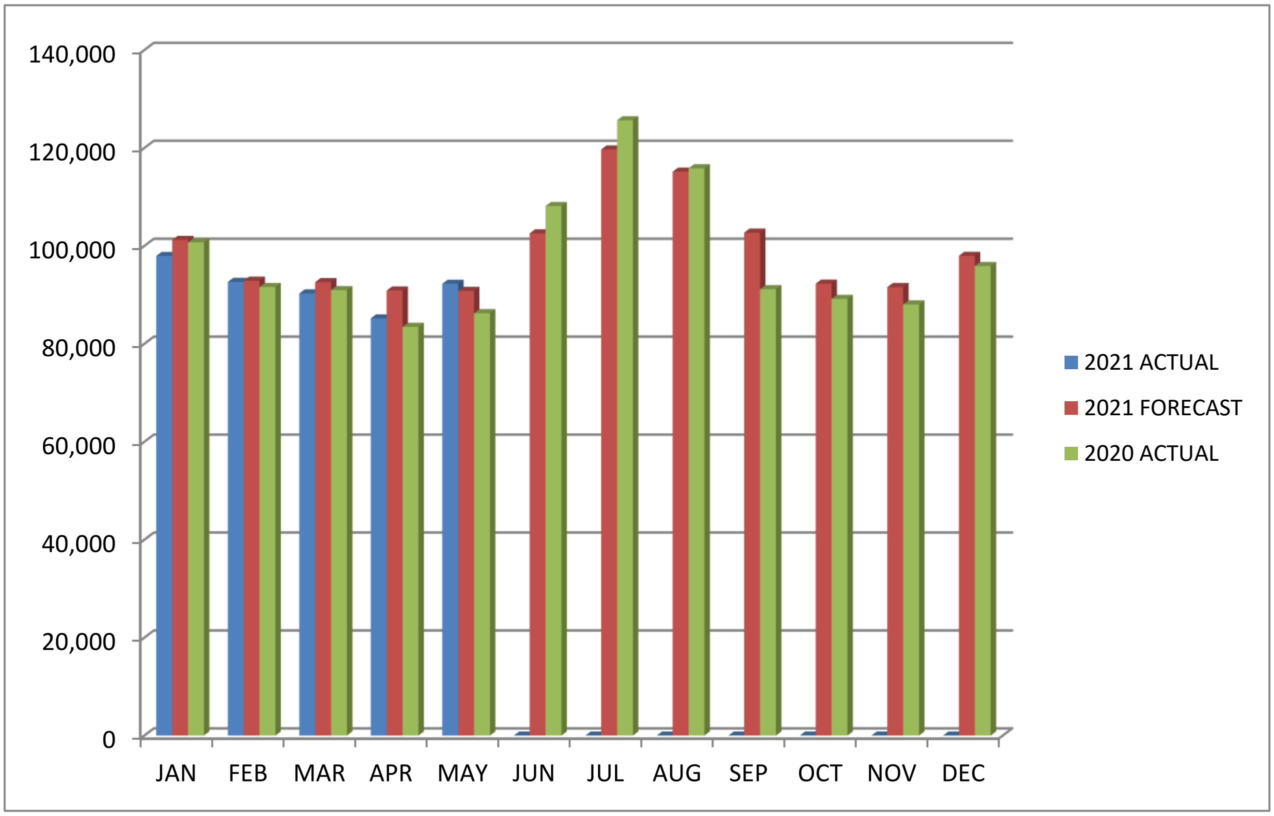
	SYSTEM ENERGY			PEAK SYSTEM DATA		
MONTH	**ACTUAL MWH**	**FORECAST MWH**	**% DIFF**	**ACTUAL MW**	**FORECAST MW**	**% DIFF**
JAN	97,934	101,211	-3.2%	164.6	182.4	-9.7%
FEB	92,648	92,886	-0.3%	172.3	179.6	-4.0%
MAR	90,288	92,601	-2.5%	151.8	158.0	-3.9%
APR	85,195	90,885	-6.3%	158.6	168.7	-6.0%
MAY	92,262	90,824	1.6%	206.9	194.6	6.3%
JUN					227.8	
JUL					265.5	
AUG					246.3	
SEP					238.8	
OCT					170.9	
NOV					171.7	
DEC					173.6	
YTD	**458,327**	**468,407**	**-2.2**			

HISTORICAL SYSTEM PEAK 292.1 MW 07/20/2011

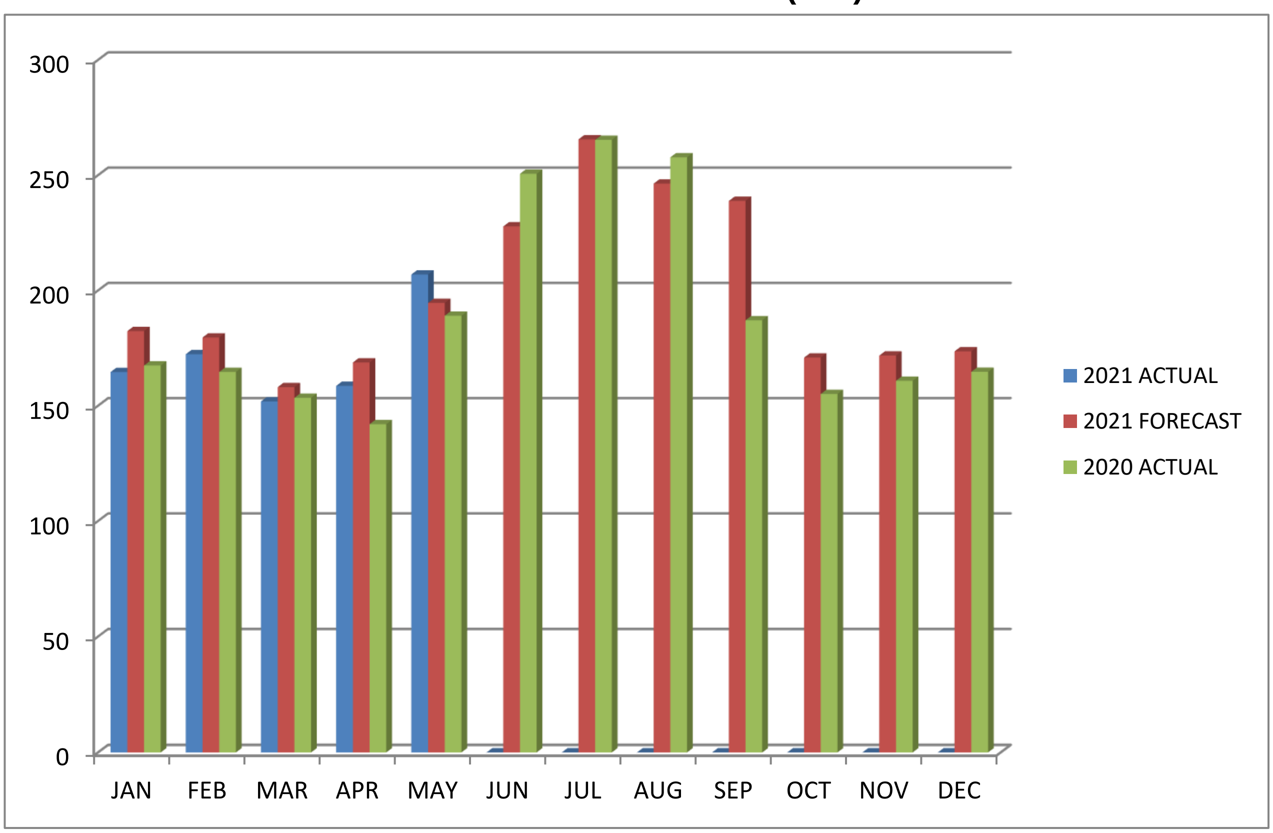
% DIFF = (ACTUAL / FORECAST X 100) - 100
MWH = MEGAWATT HOUR = 1000 KILOWATT HOURS
MW = MEGAWATT = 1000 KILOWATTS

2021 YTD SYSTEM REQUIREMENTS

Energy Required for the Month (MWH)



Peak Demand for the Month (MW)



ROCHESTER PUBLIC UTILITIES

INDEX

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DATE: May 2021

TO:

From: Julie Ackerman (507) 280-1617
Controller

SUBJ: RPU - Financial Statements

RPU - ELECTRIC UTILITY Financial Reports

RPU - WATER UTILITY Financial Reports

END OF BOARD PACKET FINANCIALS

06/16/2021

ROCHESTER PUBLIC UTILITIES

STATEMENT OF NET POSITION

ELECTRIC UTILITY

May 31, 2021

		May 2021	May 2020	Difference	% Diff.	April 2021
8	**ASSETS**					
9	**CURRENT ASSETS**					
10	CASH & INVESTMENTS					
11	Unreserved Cash & Investments	29,900,357	10,586,497	19,313,860	182.4	30,289,567
12	BOARD RESERVED CASH & INVESTMENTS					
13	Clean Air Rider Reserve	6,529,996	7,263,435	(733,439)	(10.1)	6,529,996
14	Working Funds Reserve	19,537,000	20,590,000	(1,053,000)	(5.1)	19,537,000
15	Special Capital & Major Maintnce Reserve	2,800,818	9,788,918	(6,988,100)	(71.4)	2,800,818
16	Contingency Reserve	10,943,000	10,581,000	362,000	3.4	10,943,000
17	General Capital & Major Maintnce Reserve	22,169,951	25,694,988	(3,525,037)	(13.7)	22,169,951
18	Total Reserved Cash & Investments	61,980,765	73,918,341	(11,937,576)	(16.1)	61,980,765
19	Total Cash & Investments	91,881,122	84,504,838	7,376,284	8.7	92,270,332
20	Receivables & Accrued Utility Revenues	21,746,845	18,084,187	3,662,658	20.3	20,906,946
21	Inventory	6,463,379	6,563,759	(100,381)	(1.5)	6,420,602
22	Other Current Assets	1,933,008	1,811,806	121,201	6.7	1,942,195
23	RESTRICTED ASSETS					
24	Restricted Cash and Equivalents	3,153,000	3,007,500	145,500	4.8	5,333,729
25	Total Current Assets	125,177,354	113,972,090	11,205,263	9.8	126,873,804
26	**NON-CURRENT ASSETS**					
27	RESTRICTED ASSETS					
28	RESTRICTED CASH & INVESTMENTS					
29	Debt Service Reserve	12,072,991	12,955,835	(882,844)	(6.8)	12,072,991
30	Funds Held in Trust	0	0	0	0.0	0
31	Total Restricted Cash & Investments	12,072,991	12,955,835	(882,844)	(6.8)	12,072,991
32	Total Restricted Assets	12,072,991	12,955,835	(882,844)	(6.8)	12,072,991
33	**CAPITAL ASSETS**					
34	**NON-DEPRECIABLE ASSETS**					
35	Land and Land Rights	11,264,662	9,542,782	1,721,880	18.0	9,543,522
36	Construction Work in Progress	18,813,015	12,755,158	6,057,857	47.5	18,787,032
37	Total Non-depreciable Assets	30,077,678	22,297,940	7,779,738	34.9	28,330,553
38	**DEPRECIABLE ASSETS**					
39	Utility Plant in Service, Net	245,209,638	249,566,826	(4,357,188)	(1.7)	246,321,988
40	Steam Assets, Net	1,350,054	1,644,611	(294,557)	(17.9)	1,374,601
41	Total Depreciable Assets	246,559,692	251,211,437	(4,651,745)	(1.9)	247,696,589
42	Net Capital Assets	276,637,370	273,509,377	3,127,993	1.1	276,027,142
43	Other Non-Current Assets	12,071,802	12,043,549	28,253	0.2	12,110,499
44	Total Non-Current Assets	300,782,163	298,508,761	2,273,402	0.8	300,210,632
45	**TOTAL ASSETS**	425,959,516	412,480,851	13,478,665	3.3	427,084,435
46	**DEFERRED OUTFLOWS OF RESOURCES**					
47	DEFERRED OUTFLOWS OF RESOURCES	3,608,058	1,955,171	1,652,887	84.5	3,600,738
48	**TOTAL ASSETS + DEFERRED OUTFLOW RESOURCE**	**429,567,574**	**414,436,022**	**15,131,552**	**3.7**	**430,685,173**
49	**LIABILITIES**					
50	**CURRENT LIABILITIES**					
51	Accounts Payable	10,299,673	10,145,272	154,401	1.5	9,088,109
52	Due to other funds	3,567,559	3,348,142	219,417	6.6	3,534,879
53	Customer Deposits	1,971,829	1,750,492	221,337	12.6	1,958,730
54	Compensated absences	2,130,569	1,900,948	229,621	12.1	2,104,751
55	Accrued Salaries & Wages	516,141	424,098	92,043	21.7	420,266
56	Interest Payable	0	0	0	0.0	2,741,062
57	Current Portion of Long Term Debt	6,515,000	6,015,000	500,000	8.3	6,515,000
58	Misc Other Current Liabilities	245	0	245	0.0	6
59	Total Current Liabilities	25,001,016	23,583,952	1,417,065	6.0	26,362,803
60	**NON-CURRENT LIABILITIES**					
61	Compensated absences	1,521,829	1,346,570	175,260	13.0	1,513,930
62	Other Non-Current Liabilities	14,291,386	12,590,021	1,701,365	13.5	14,291,386
63	Unearned Revenues	1,810,306	9,224,855	(7,414,548)	(80.4)	1,802,015
64	Long-Term Debt	175,539,157	183,190,290	(7,651,133)	(4.2)	175,675,069
65	Total Non-Current Liabilities	193,162,679	206,351,735	(13,189,056)	(6.4)	193,282,401
66	**TOTAL LIABILITIES**	218,163,696	229,935,687	(11,771,991)	(5.1)	219,645,203
67	**DEFERRED INFLOWS OF RESOURCES**					
68	DEFERRED INFLOWS OF RESOURCES	1,434,049	3,044,338	(1,610,289)	(52.9)	1,510,085
69	**NET POSITION**					
70	Net Investment in Capital Assets	108,649,954	98,160,736	10,489,218	10.7	105,182,984
71	Total Restricted Net Position	3,153,000	3,007,500	145,500	4.8	2,592,667
72	Unrestricted Net Position	98,166,875	80,287,761	17,879,114	22.3	101,754,234
73	**TOTAL NET POSITION**	209,969,829	181,455,997	28,513,832	15.7	209,529,885
74	**TOTAL LIAB,DEFERRED INFLOWS,NET POSITION**	**429,567,574**	**414,436,022**	**15,131,552**	**3.7**	**430,685,173**

1 06/16/2021

2 **ROCHESTER PUBLIC UTILITIES**

3 **Statement of Revenues, Expenses & Changes in Net Position**

4

5 **May , 2021**

6 **YEAR TO DATE**

Row		Actual YTD	Original Budget YTD	Actual to Original Budget	% Var.	Last Yr Actual YTD
7						
8	**SALES REVENUE**					
9	Retail Revenue					
10	Electric - Residential Service	20,292,799	20,489,975	(197,176)	(1.0)	19,902,49
11	Electric - General & Industrial Service	32,173,968	32,782,395	(608,426)	(1.9)	31,573,45
12	Electric - Public Street & Highway Light	693,533	618,627	74,905	12.1	646,44
13	Electric - Rental Light Revenue	76,980	105,492	(28,512)	(27.0)	81,24
14	Electric - Interdepartmentl Service	385,475	335,959	49,515	14.7	380,66
15	Electric - Power Cost Adjustment	31,548	(320,337)	351,884	109.8	(57,98
16	Electric - Clean Air Rider	848,445	819,934	28,512	3.5	783,48
17	Electric - Total Retail Revenue	54,502,748	54,832,044	(329,297)	(0.6)	53,309,81
18	Wholesale Electric Revenue					
19	Energy & Fuel Reimbursement	1,416,687	974,836	441,851	45.3	284,10
20	Capacity & Demand	111,875	63,090	48,785	77.3	64,03
21	Total Wholesale Electric Revenue	1,528,562	1,037,926	490,636	47.3	348,13
22	Steam Sales Revenue	3,310,072	2,020,000	1,290,072	63.9	1,986,18
23	TOTAL SALES REVENUE	59,341,382	57,889,970	1,451,412	2.5	55,644,14
24	**COST OF REVENUE**					
25	Purchased Power	33,880,646	35,039,052	(1,158,406)	(3.3)	33,230,59
26	Generation Fuel, Chemicals & Utilities	3,215,554	1,803,143	1,412,411	78.3	1,243,54
27	TOTAL COST OF REVENUE	37,096,200	36,842,196	254,005	0.7	34,474,13
28	**GROSS MARGIN**					
29	Retail	20,622,101	19,792,992	829,109	4.2	20,079,22
30	Wholesale	1,623,081	1,254,783	368,298	29.4	1,090,78
31	TOTAL GROSS MARGIN	22,245,182	21,047,775	1,197,407	5.7	21,170,01
32	**FIXED EXPENSES**					
33	Utilities Expense	193,947	198,088	(4,141)	(2.1)	188,31
34	Depreciation & Amortization	6,142,179	5,833,599	308,580	5.3	6,164,67
35	Salaries & Benefits	8,437,301	7,550,467	886,833	11.7	8,452,86
36	Materials, Supplies & Services	3,948,815	4,817,418	(868,604)	(18.0)	4,451,33
37	Inter-Utility Allocations	(787,673)	(716,250)	(71,423)	(10.0)	(721,93
38	TOTAL FIXED EXPENSES	17,934,568	17,683,322	251,245	1.4	18,535,23
39	Other Operating Revenue	3,962,933	4,096,080	(133,147)	(3.3)	2,438,48
40	**NET OPERATING INCOME (LOSS)**	8,273,547	7,460,532	813,015	10.9	5,073,25
41	NON-OPERATING REVENUE / (EXPENSE)					
42	Investment Income (Loss)	512,225	727,273	(215,048)	(29.6)	624,11
43	Interest Expense	(2,338,243)	(2,575,494)	237,251	9.2	(2,640,18
44	Amortization of Debt Issue Costs	(42,726)	(32,155)	(10,571)	(32.9)	(33,71
45	Miscellaneous - Net	(43,701)	(2,250)	(41,451)	(1,842.3)	(58,85
46	TOTAL NON-OPERATING REV (EXP)	(1,912,446)	(1,882,627)	(29,819)	(1.6)	(2,108,63
47	**INCOME (LOSS) BEFORE TRANSFERS / CAPITAL CONTRIBUTIONS**	**6,361,102**	**5,577,906**	**783,196**	**14.0**	**2,964,61**
48	Transfers Out	(3,275,156)	(3,390,806)	115,650	3.4	(3,250,31
49	Capital Contributions	1,411,464	1,925,938	(514,474)	(26.7)	213,24
50	CHANGE IN NET POSITION	**4,497,409**	**4,113,038**	**384,372**	**9.3**	**(72,45**
51	Net Position, Beginning	205,472,420				181,528,44
52	**NET POSITION, ENDING**	**209,969,829**				**181,455,99**
53						

54 Rolling 12 Months | Planned for Curr Year

55 **Debt Coverage Ratio** 3.83 | 2.93

6/16/2021 12:29 PM

Attachment: Division Reports June 2021 (13522 : Division Reports & Metrics - June 2021)

06/17/21

1 **ROCHESTER PUBLIC UTILITIES**

2 **STATEMENT OF CASH FLOWS**

3 **ELECTRIC UTILITY**

4 **FOR**

5 **MAY, 2021**

6 **YEAR-TO-DATE**

No.		Actual YTD	Last Yr Actual YTD
7		**Actual YTD**	**Last Yr Actual YTD**
8	CASH FLOWS FROM OPERATING ACTIVITIES		
9	Cash Received From Customers	57,113,856	56,384,016
10	Cash Received From Other Revenue Sources	4,267,058	0
11	Cash Received From Wholesale & Steam Customer	4,865,003	2,428,254
12	Cash Paid for:		
13	Purchased Power	(33,694,872)	(33,250,355)
14	Operations and Maintenance	(11,488,403)	(12,924,735)
15	Fuel	(3,132,914)	(1,618,277)
16	Payment in Lieu of Taxes	(3,308,778)	(3,362,722)
17	Net Cash Provided by(Used in) Utility		
18	Operating Activities	14,620,949	7,656,181
19	Sewer, Storm Water, Sales Tax & MN Water Fee Collections		
20	Receipts from Customers	18,332,117	17,706,642
21	Remittances to Government Agencies	(18,049,085)	(17,621,166)
22	Net Cash Provided by(Used in) Non-Utility		
23	Operating Activities	283,032	85,476
24	NET CASH PROVIDED BY(USED IN)		
25	OPERATING ACTIVITIES	14,903,981	7,741,657
26	CASH FLOWS FROM CAPITAL & RELATED		
27	FINANCING ACTIVITIES		
28	Additions to Utility Plant & Other Assets	(7,767,377)	(6,094,667)
29	Payments related to Service Territory Acquisition	(40,909)	(81,473)
30	Proceeds on Long-Term Debt	3,175,000	0
31	Net Bond/Loan Receipts	0	0
32	Cash Paid for Interest & Commissions	(7,775,658)	(4,040,050)
33	NET CASH PROVIDED BY(USED IN)		
34	CAPITAL & RELATED ACTIVITIES	(12,408,944)	(10,216,190)
35	CASH FLOWS FROM INVESTING ACTIVITIES		
36	Interest Earnings on Investments	68,880	83,808
37	Construction Fund (Deposits)Draws	0	0
38	Bond Reserve Account	(1,095,627)	(1,832,908)
39	Escrow/Trust Account Activity	0	756
40	NET CASH PROVIDED BY(USED IN)		
41	INVESTING ACTIVITIES	(1,026,747)	(1,748,344)
42	Net Increase(Decrease) in Cash & Investments	1,468,290	(4,222,877)
43	Cash & Investments, Beginning of Period	90,412,832	88,727,715
44	**CASH & INVESTMENTS, END OF PERIOD**	**91,881,122**	**84,504,838**
45	Externally Restricted Funds	15,225,991	15,963,335
46	Grand Total	107,107,113	100,468,173

6/16/2021

1 **ROCHESTER PUBLIC UTILITIES**

2 **PRODUCTION & SALES STATISTICS**

3 **ELECTRIC UTILITY**

4 **May , 2021**

5 YEAR-TO-DATE

#		# Custs	Actual YTD	Budget YTD	Variance	% Var.	Last Yr Actual YTD
8							
9	**ENERGY SUPPLY (kWh)**	*(primarily calendar month)*					
10	Net Generation						
11	IBM Diesel Generators		12,019	0	12,019	-	10,104
12	Lake Zumbro Hydro		4,436,076	5,852,304	(1,416,228)	(24.2)	8,195,582
13	Cascade Creek Gas Turbine		9,626,970	5,506,000	4,120,970	74.8	1,364,232
14	Westside Energy Station		7,948,600	14,419,000	(6,470,400)	(44.9)	7,975,521
15	Total Net Generation		22,023,665	25,777,304	(3,753,639)	(14.6)	17,545,439
16	Other Power Supply						
17	Firm Purchases		454,239,903	462,554,268	(8,314,365)	(1.8)	446,723,104
18	Non-Firm Purchases		126,831	0	126,831	-	0
19	LRP Received		0	0	0	-	0
20	Total Other Power Supply		454,366,734	462,554,268	(8,187,534)	(1.8)	446,723,104
21	TOTAL ENERGY SUPPLY		476,390,399	488,331,572	(11,941,173)	(2.4)	464,268,543
22	**ENERGY USES (kWh)**	*(primarily billing period)*					
23	Retail Sales	**# Custs**					
24	Electric - Residential Service	52,871	140,108,781	140,984,954	(876,173)	(0.6)	137,052,941
25	Electric - General Service & Industrial	5,116	296,174,121	309,112,931	(12,938,810)	(4.2)	295,330,977
26	Electric - Street & Highway Lighting	3	1,933,939	2,549,227	(615,288)	(24.1)	2,527,742
27	Electric - Rental Lights	n/a	342,832	377,372	(34,540)	(9.2)	376,875
28	Electric - Interdptmntl Service	1	2,836,050	2,494,145	341,905	13.7	2,745,246
29	Total Customers	57,991					
30	Total Retail Sales		441,395,723	455,518,629	(14,122,906)	(3.1)	438,033,781
31	Wholesale Sales		17,630,990	19,925,000	(2,294,010)	(11.5)	9,397,477
32	Company Use		998,538	1,463,393	(464,855)	(31.8)	1,042,037
33	TOTAL ENERGY USES		460,025,251	476,907,022	(16,881,771)	(3.5)	448,473,295
34	Lost & Unaccntd For Last 12 Months		38,846,985	3.2%			
35	**STEAM SALES (mlbs)**	*(primarily billing period)*					
36	Steam Sales in Mlbs		190,090	242,792	(52,702)	(21.7)	201,860

6/16/2021

1 **ROCHESTER PUBLIC UTILITIES**

2 **PRODUCTION & SALES STATISTICS (continued)**

3 **ELECTRIC UTILITY**

4 **May , 2021**

5 YEAR-TO-DATE

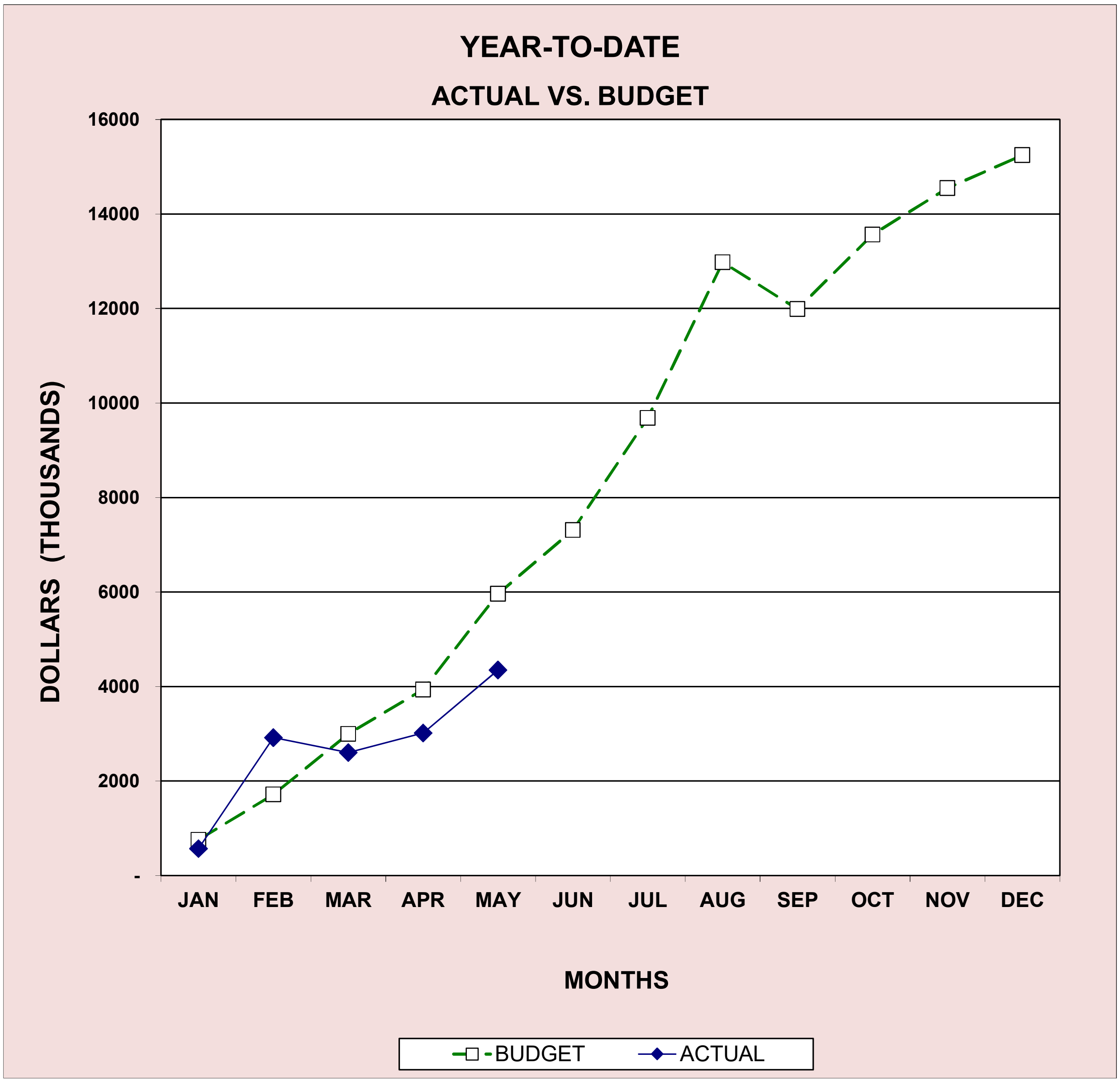
Row		Actual YTD		Budget YTD		Variance	% Var.	Last Yr Actual YTD	
8									
9	FUEL USAGE	*(calendar month)*							
10	**Gas Burned**								
11	SLP	260,551	MCF	320,486	MCF	(59,935)	(18.7)	270,887	MCF
12	Cascade	73,832	MCF	46,934	MCF	26,898	57.3	14,507	MCF
13	Westside	61,414	MCF	97,451	MCF	(36,037)	(37.0)	61,664	MCF
14	Total Gas Burned	395,797	MCF	464,871	MCF	(69,074)	(14.9)	347,058	MCF
15	**Oil Burned**								
16	Cascade	205,555	GAL	0	GAL	205,555	-	1,949	GAL
17	IBM	979	GAL	0	GAL	979	-	813	GAL
18	Total Oil Burned	206,534	GAL	0	GAL	206,534	-	2,762	GAL

CAPITAL EXPENDITURES
ELECTRIC

May, 2021

Current Year	
ANNUAL BUDGET	15,246,736
ACTUAL YTD	4,349,975
% OF BUDGET	28.5%

Prior Years Ending Dec 31st			
	2020	2019	2018
	15,059,888	21,990,984	31,779,490
	10,078,628	11,174,211	16,646,579
	66.9%	50.8%	52.4%

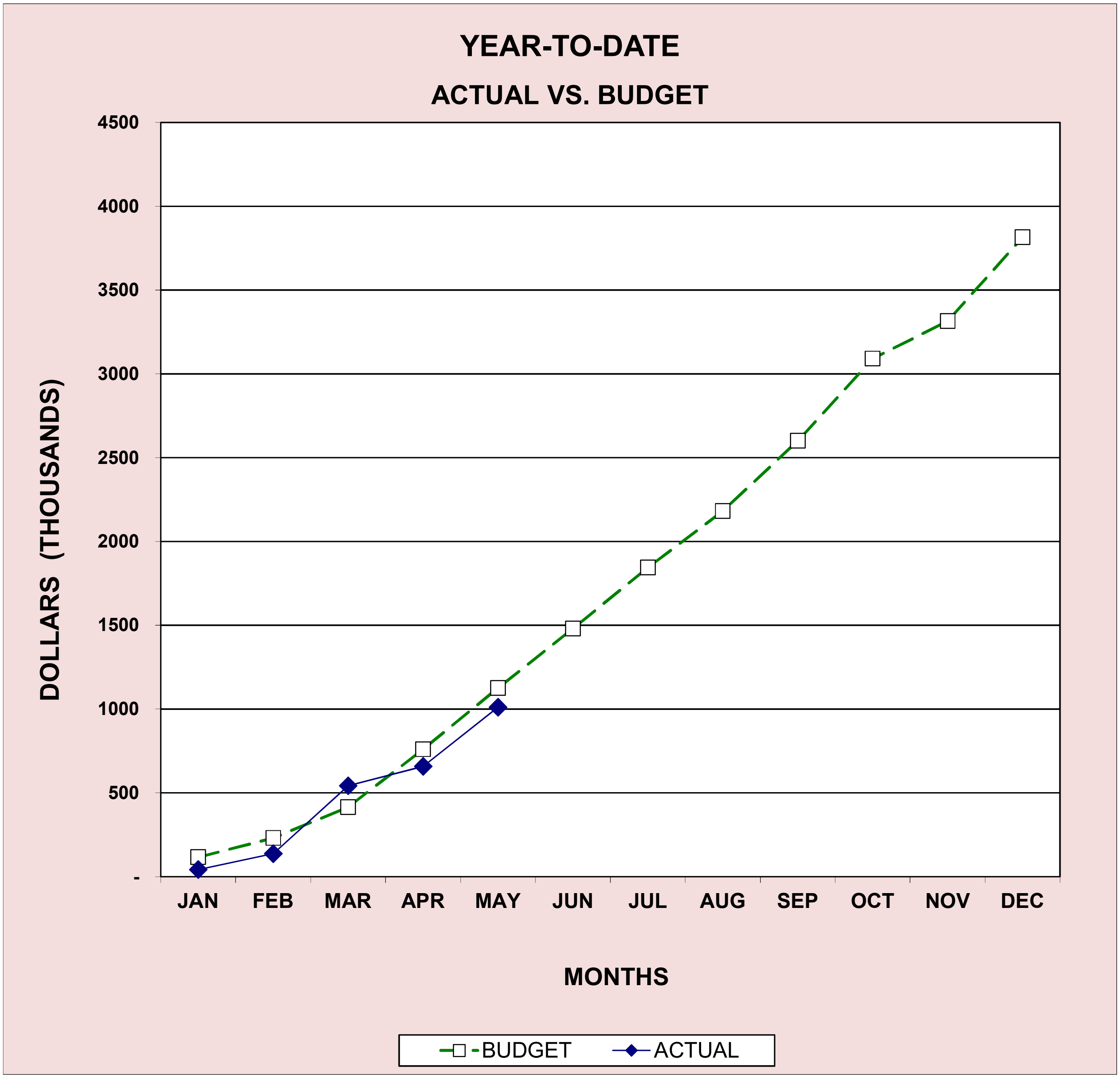


MAJOR MAINTENANCE EXPENDITURES
ELECTRIC

May, 2021

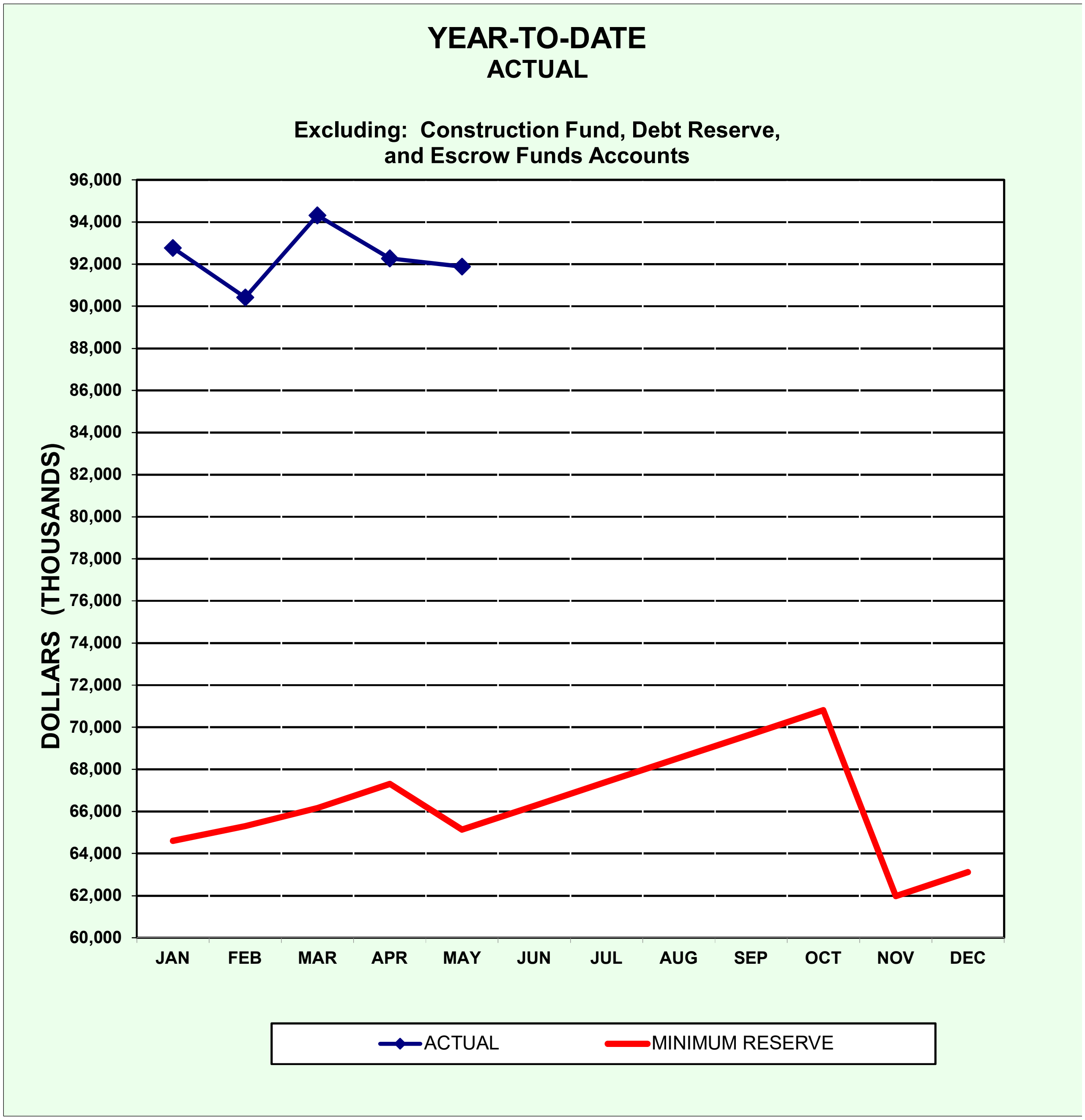
Current Year	
ANNUAL BUDGET	3,815,243
ACTUAL YTD	1,010,844
% OF BUDGET	26.5%

Prior Years Ending Dec 31st		
2020	2019	2018
4,010,088	3,353,049	3,038,283
3,111,620	2,881,017	2,421,088
77.6%	85.9%	79.7%



CASH AND TEMPORARY INVESTMENTS
ELECTRIC

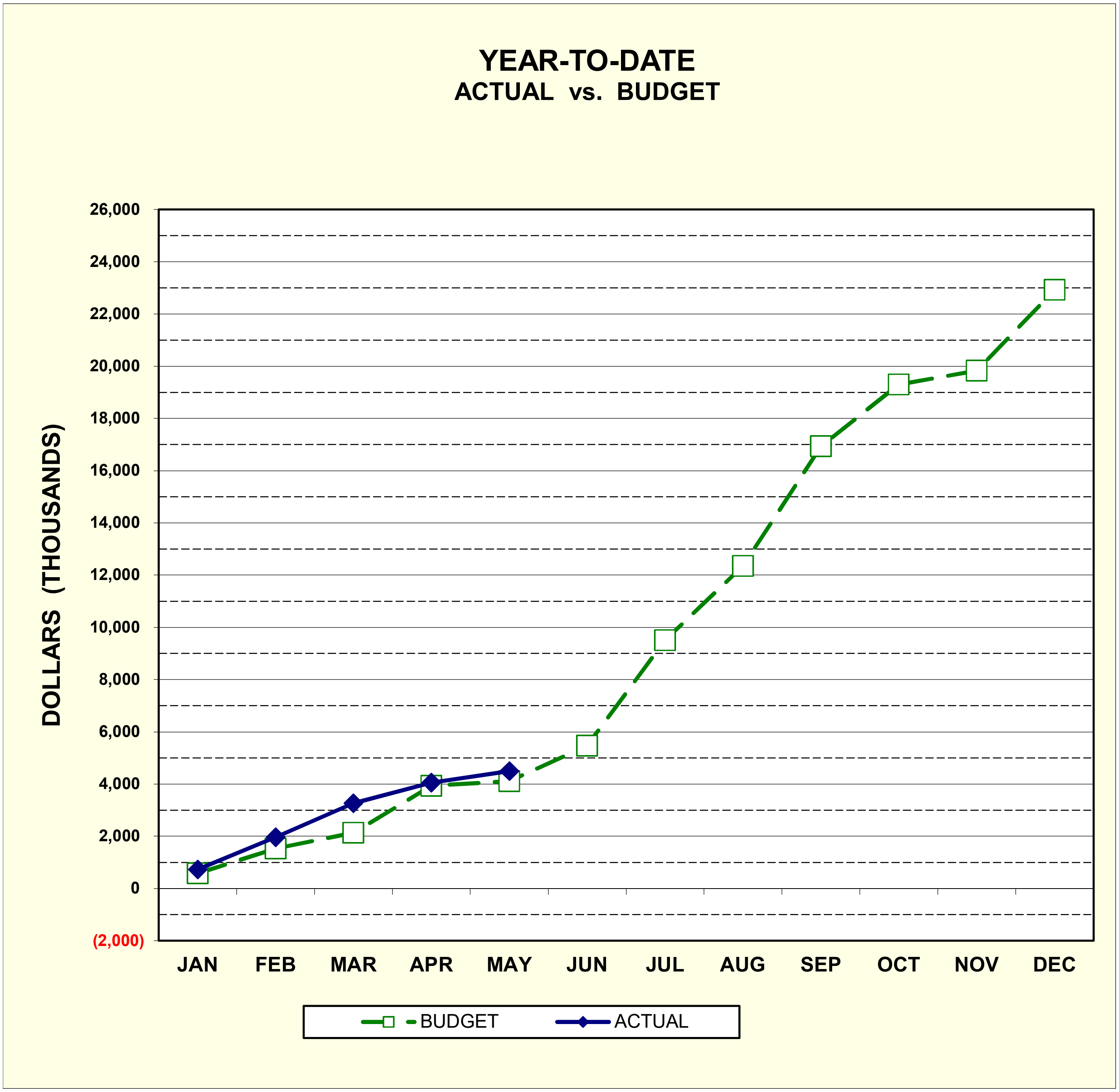
May, 2021



CHANGE IN NET POSITION

ELECTRIC

May, 2021



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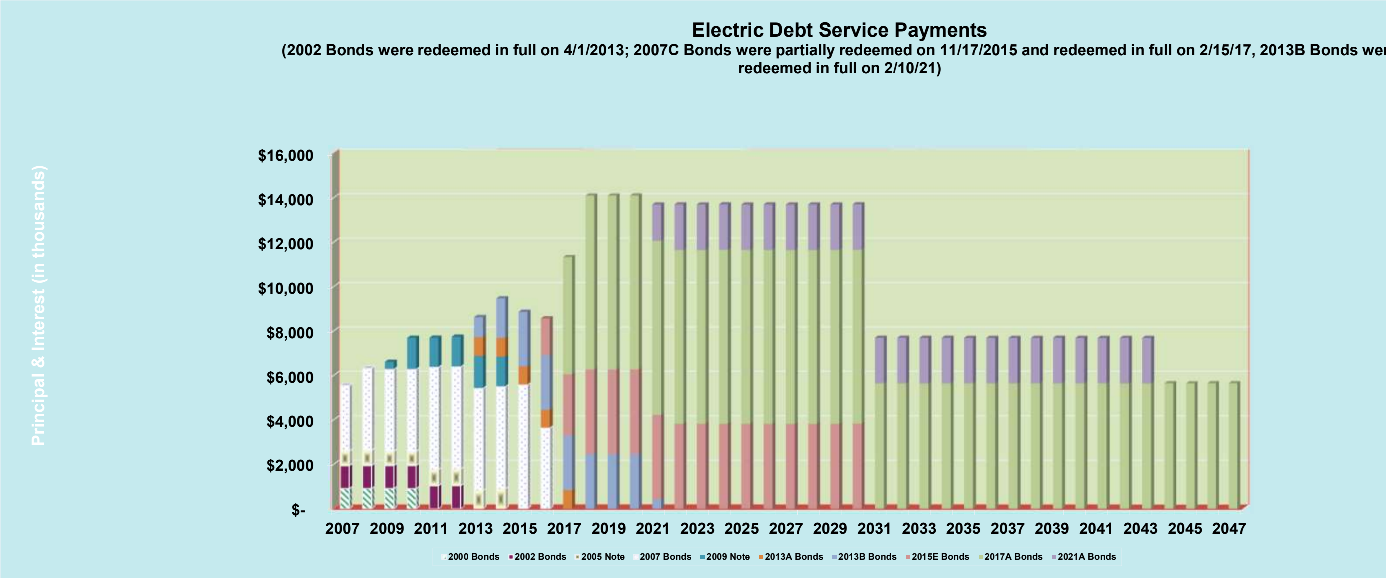

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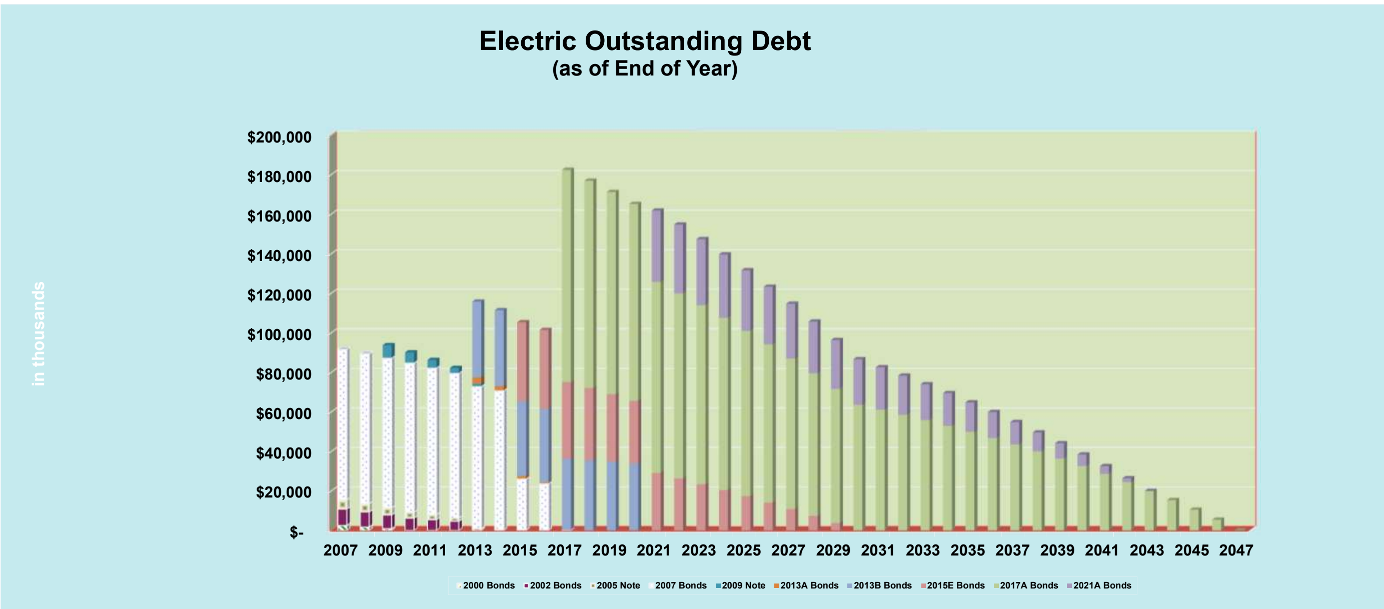


06/16/2021

ROCHESTER PUBLIC UTILITIES
STATEMENT OF NET POSITION
WATER UTILITY
May 31, 2021

	May 2021	May 2020	Difference	% Diff.	April 2021
ASSETS					
CURRENT ASSETS					
CASH & INVESTMENTS					
Unreserved Cash & Investments	3,949,898	3,595,014	354,884	9.9	3,772,094
BOARD RESERVED CASH & INVESTMENTS					
Working Funds Reserve	1,045,000	1,086,000	(41,000)	(3.8)	1,045,000
Capital & Major Maintenance Reserve	5,766,000	5,238,000	528,000	10.1	5,766,000
Contingency Reserve	1,622,000	1,584,000	38,000	2.4	1,622,000
Total Reserved Cash & Investments	8,433,000	7,908,000	525,000	6.6	8,433,000
Total Cash & Investments	12,382,898	11,503,014	879,884	7.6	12,205,094
Receivables & Accrued Utility Revenues	1,063,311	971,471	91,840	9.5	886,899
Inventory	207,488	206,645	843	0.4	205,310
Other Current Assets	91,305	60,092	31,213	51.9	108,085
Total Current Assets	13,745,002	12,741,222	1,003,781	7.9	13,405,387
CAPITAL ASSETS					
NON-DEPRECIABLE ASSETS					
Land and Land Rights	677,486	677,486	0	0.0	677,486
Construction Work in Progress	4,829,809	2,195,140	2,634,669	120.0	4,597,862
Total Non-depreciable Assets	5,507,295	2,872,626	2,634,669	91.7	5,275,348
DEPRECIABLE ASSETS					
Utility Plant in Service, Net	94,283,030	95,227,885	(944,855)	(1.0)	94,501,217
Net Capital Assets	99,790,325	98,100,511	1,689,814	1.7	99,776,565
Total Non-Current Assets	99,790,325	98,100,511	1,689,814	1.7	99,776,565
TOTAL ASSETS	113,535,327	110,841,733	2,693,594	2.4	113,181,952
DEFERRED OUTFLOWS OF RESOURCES					
DEFERRED OUTFLOWS OF RESOURCES	210,792	126,479	84,313	66.7	208,036
TOTAL ASSETS + DEFERRED OUTFLOW RESOURCE	113,746,120	110,968,212	2,777,907	2.5	113,389,988
LIABILITIES					
CURRENT LIABILITIES					
Accounts Payable	400,806	237,903	162,903	68.5	138,806
Customer Deposits	117,727	116,047	1,679	1.4	122,852
Compensated Absences	340,679	336,892	3,787	1.1	334,876
Accrued Salaries & Wages	69,705	52,753	16,953	32.1	57,696
Total Current Liabilities	928,917	743,595	185,321	24.9	654,230
NON-CURRENT LIABILITIES					
Compensated Absences	219,906	149,958	69,948	46.6	218,516
Other Non-Current Liabilities	1,807,972	1,561,107	246,866	15.8	1,807,972
Total Non-Current Liabilities	2,027,878	1,711,065	316,813	18.5	2,026,489
TOTAL LIABILITIES	2,956,795	2,454,660	502,135	20.5	2,680,719
DEFERRED INFLOWS OF RESOURCES					
DEFERRED INFLOWS OF RESOURCES	698,772	888,299	(189,527)	(21.3)	798,690
NET POSITION					
Net Investment in Capital Assets	99,790,325	98,100,511	1,689,814	1.7	99,776,565
Unrestricted Net Assets (Deficit)	10,300,228	9,524,742	775,486	8.1	10,134,014
TOTAL NET POSITION	110,090,553	107,625,253	2,465,300	2.3	109,910,580
TOTAL LIAB,DEFERRED INFLOWS,NET POSITION	113,746,120	110,968,212	2,777,907	2.5	113,389,988

1 06/16/2021

2 ROCHESTER PUBLIC UTILITIES

3 Statement of Revenues, Expenses & Changes in Net Position

4 WATER UTILITY

5 May , 2021

6 YEAR TO DATE

7		Actual YTD	Original Budget YTD	Actual to Original Budget	% Var.	Last Yr Actual YTD
8	**RETAIL REVENUE**					
9	Water - Residential Service	2,487,943	2,425,226	62,717	2.6	2,478,381
10	Water - Commercial Service	1,152,154	1,172,113	(19,959)	(1.7)	1,114,717
11	Water - Industrial Service	236,561	352,670	(116,109)	(32.9)	234,521
12	Water - Public Fire Protection	247,621	249,746	(2,125)	(0.9)	244,931
13	Water - Interdepartmental Service	9,060	12,725	(3,665)	(28.8)	7,727
14	TOTAL RETAIL REVENUE	4,133,340	4,212,480	(79,140)	(1.9)	4,080,277
15	**COST OF REVENUE**					
16	Utilities Expense	395,753	330,326	65,427	19.8	399,863
17	Water Treatment Chemicals/Demin Water	36,315	42,251	(5,936)	(14.0)	50,193
18	Billing Fees	311,326	311,714	(388)	(0.1)	208,770
19	TOTAL COST OF REVENUE	743,395	684,291	59,104	8.6	658,826
20	**GROSS MARGIN**	3,389,945	3,528,189	(138,244)	(3.9)	3,421,451
21	**FIXED EXPENSES**					
22	Depreciation & Amortization	1,141,080	1,190,100	(49,020)	(4.1)	1,143,634
23	Salaries & Benefits	1,189,797	1,253,946	(64,149)	(5.1)	1,129,732
24	Materials, Supplies & Services	396,692	540,412	(143,720)	(26.6)	380,942
25	Inter-Utility Allocations	787,673	716,250	71,423	10.0	721,939
26	TOTAL FIXED EXPENSES	3,515,243	3,700,708	(185,465)	(5.0)	3,376,246
27	Other Operating Revenue	600,094	603,572	(3,478)	(0.6)	604,632
28	**NET OPERATING INCOME (LOSS)**	474,796	431,053	43,743	10.1	649,837
29	NON-OPERATING REVENUE / (EXPENSE)					
30	Investment Income (Loss)	84,942	77,143	7,799	10.1	101,728
31	Interest Expense	(10)	0	(10)	0.0	(66)
32	Miscellaneous - Net	(831)	0	(831)	0.0	(224)
33	TOTAL NON-OPERATING REV (EXP)	84,102	77,143	6,959	9.0	101,438
34	**INCOME (LOSS) BEFORE TRANSFERS / CAPITAL CONTRIBUTIONS**	**558,898**	**508,196**	**50,702**	**10.0**	**751,276**
35	Transfers Out	(138,853)	(134,517)	(4,336)	(3.2)	(137,369)
36	Capital Contributions	0	0	0	0.0	0
37	CHANGE IN NET POSITION	**420,044**	**373,679**	**46,366**	**12.4**	**613,907**
38	Net Position, Beginning	109,670,508				107,011,346
39	**NET POSITION, ENDING**	**110,090,553**				**107,625,253**

06/17/21

1 **ROCHESTER PUBLIC UTILITIES**

2 **STATEMENT OF CASH FLOWS**

3 **WATER UTILITY**

4 **FOR**

5 **MAY, 2021**

6 **YEAR-TO-DATE**

		Actual YTD	Last Yr Actual YTD
7			
8	CASH FLOWS FROM OPERATING ACTIVITIES		
9	Cash Received From Customers	5,139,410	5,036,046
10	Cash Paid for:		
11	Operations and Maintenance	(3,149,356)	(3,086,223)
12	Payment in Lieu of Taxes	(130,988)	(132,686)
13	Net Cash Provided by(Used in) Utility		
14	Operating Activities	1,859,066	1,817,137
15	Sales Tax & MN Water Fee Collections		
16	Receipts from Customers	152,429	212,402
17	Remittances to Government Agencies	(150,641)	(151,933)
18	Net Cash Provided by(Used in) Non-Utility		
19	Operating Activities	1,788	60,469
20	NET CASH PROVIDED BY(USED IN)		
21	OPERATING ACTIVITIES	1,860,854	1,877,606
22	CASH FLOWS FROM CAPITAL & RELATED		
23	FINANCING ACTIVITIES		
24	Additions to Utility Plant & Other Assets	(1,538,321)	(1,005,452)
25	Payment on Long-Term Debt	0	0
26	Net Loan Receipts	0	0
27	Cash Paid for Interest & Commissions	0	0
28	NET CASH PROVIDED BY(USED IN)		
29	CAPITAL & RELATED ACTIVITIES	(1,538,321)	(1,005,452)
30	CASH FLOWS FROM INVESTING ACTIVITIES		
31	Interest Earnings on Investments	84,933	101,663
32	NET CASH PROVIDED BY(USED IN)		
33	INVESTING ACTIVITIES	84,933	101,663
34	Net Increase(Decrease) in Cash & Investments	407,466	973,817
35	Cash & Investments, Beginning of Period	11,975,432	10,529,197
36	**CASH & INVESTMENTS, END OF PERIOD**	12,382,898	11,503,014

6/16/2021

1 **ROCHESTER PUBLIC UTILITIES**

2 **PRODUCTION & SALES STATISTICS**

3 **WATER UTILITY**

4 **May , 2021**

5 YEAR-TO-DATE

#		# Custs	Actual YTD (ccf)	Budget YTD (ccf)	Variance (ccf)	% Var.	Last Yr Actual YTD
9	PUMPAGE *(primarily calendar month)*						
10	TOTAL PUMPAGE		2,160,015	2,006,215	153,800	7.7	2,105,546
11	RETAIL SALES *(primarily billing period)*						
12	Water - Residential Service	37,357	1,019,975	934,985	84,990	9.1	1,030,785
13	Water - Commercial Service	3,735	752,742	771,329	(18,587)	(2.4)	724,526
14	Water - Industrial Service	23	239,969	287,897	(47,928)	(16.6)	237,329
15	Water - Interdptmntl Service	1	7,291	10,517	(3,226)	(30.7)	5,740
16	Total Customers	41,116					
17	TOTAL RETAIL SALES		2,019,977	2,004,728	15,249	0.8	1,998,379
18	Lost & Unaccntd For Last 12 Months		311,481	5.3%			

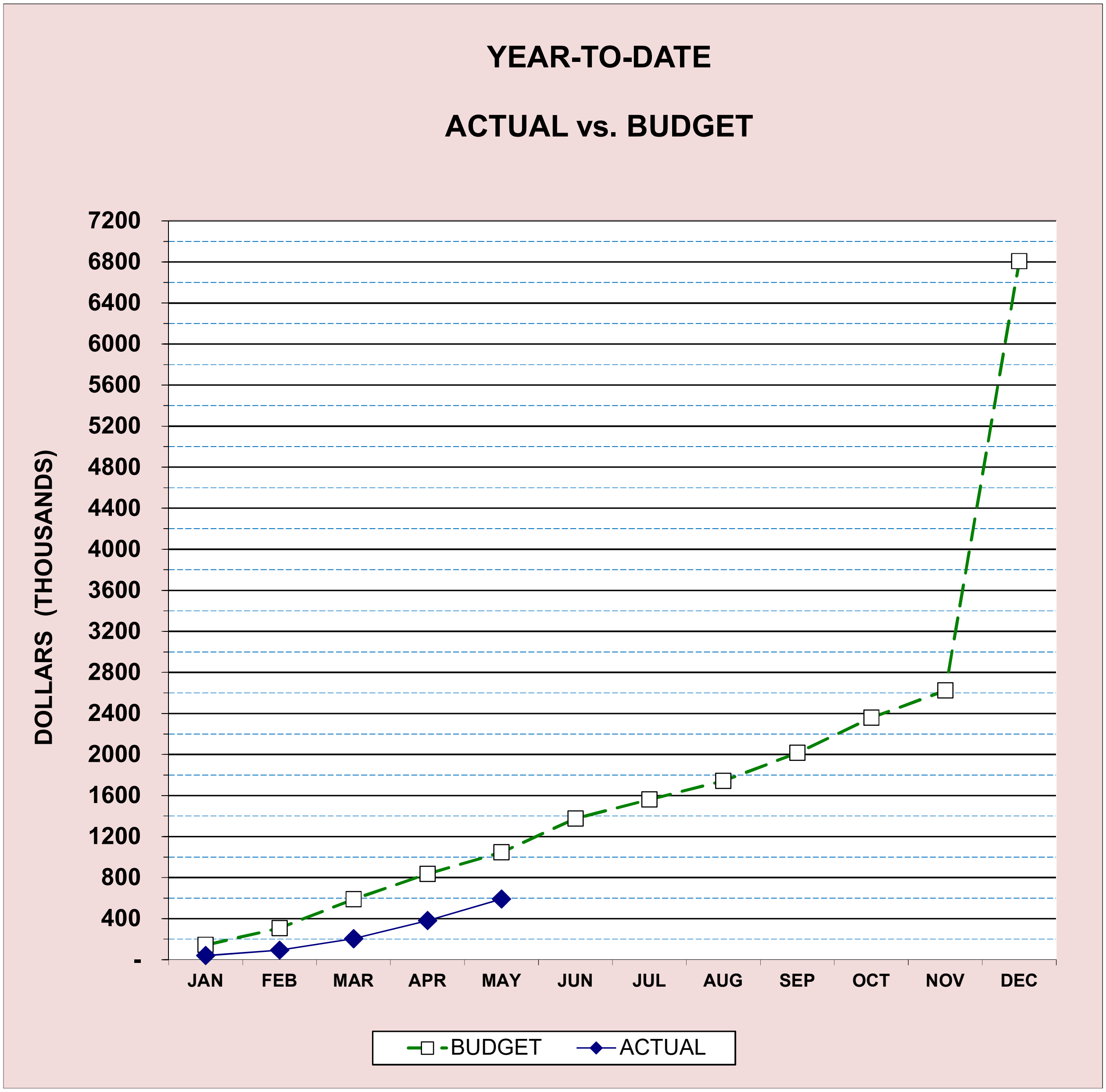
CAPITAL EXPENDITURES
WATER

May, 2021

Current Year	
ANNUAL BUDGET	6,807,825
ACTUAL YTD	591,225
% OF BUDGET	8.7%

Prior Years Ending Dec 31st

2020	2019	2018
5,917,740	4,554,317	3,171,521
2,365,830	1,689,025	2,264,812
40.0%	37.1%	71.4%



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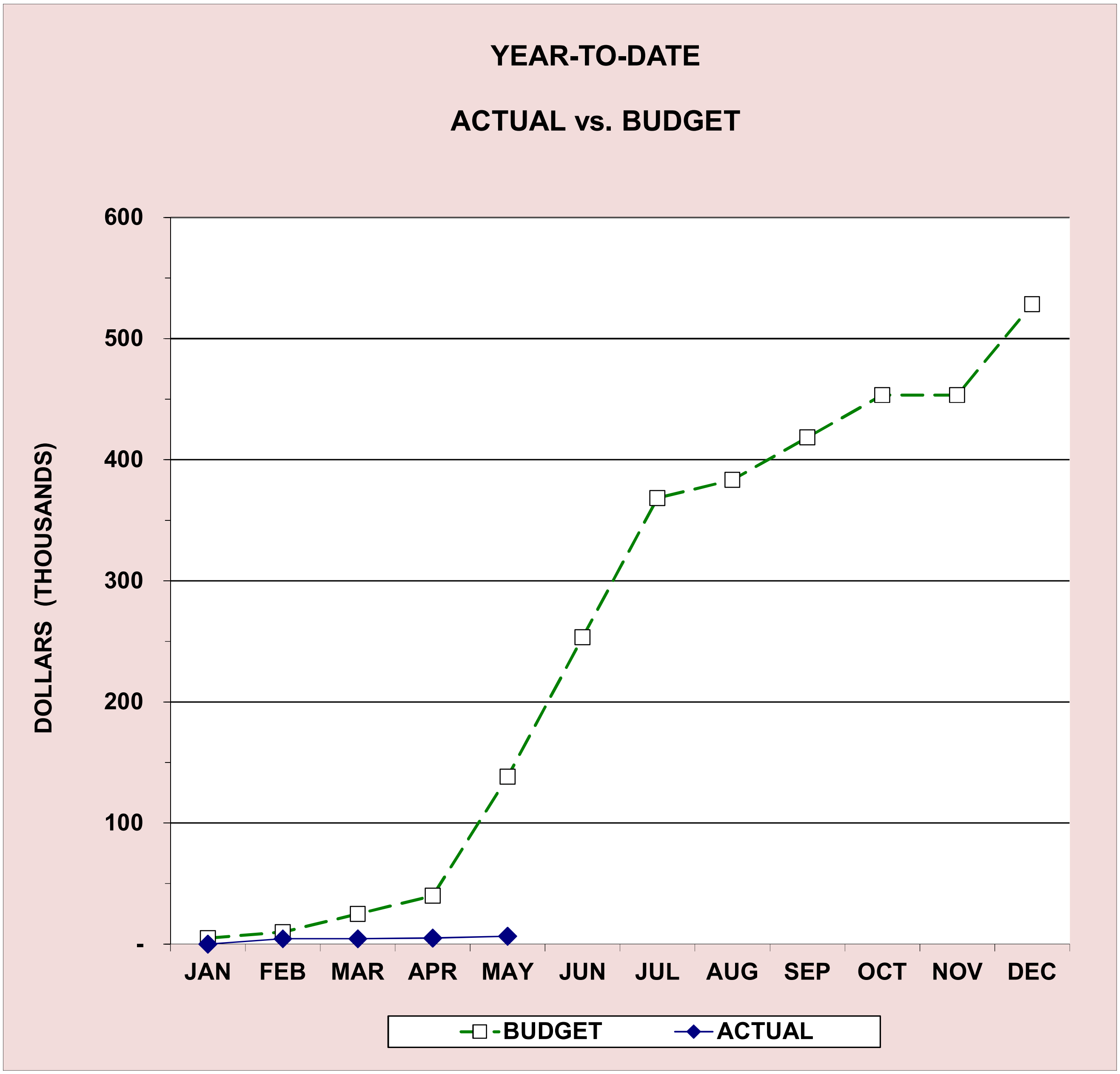
MAJOR MAINTENANCE EXPENDITURES
WATER

May, 2021

Current Year	
ANNUAL BUDGET	528,408
ACTUAL YTD	6,563
% OF BUDGET	1.2%

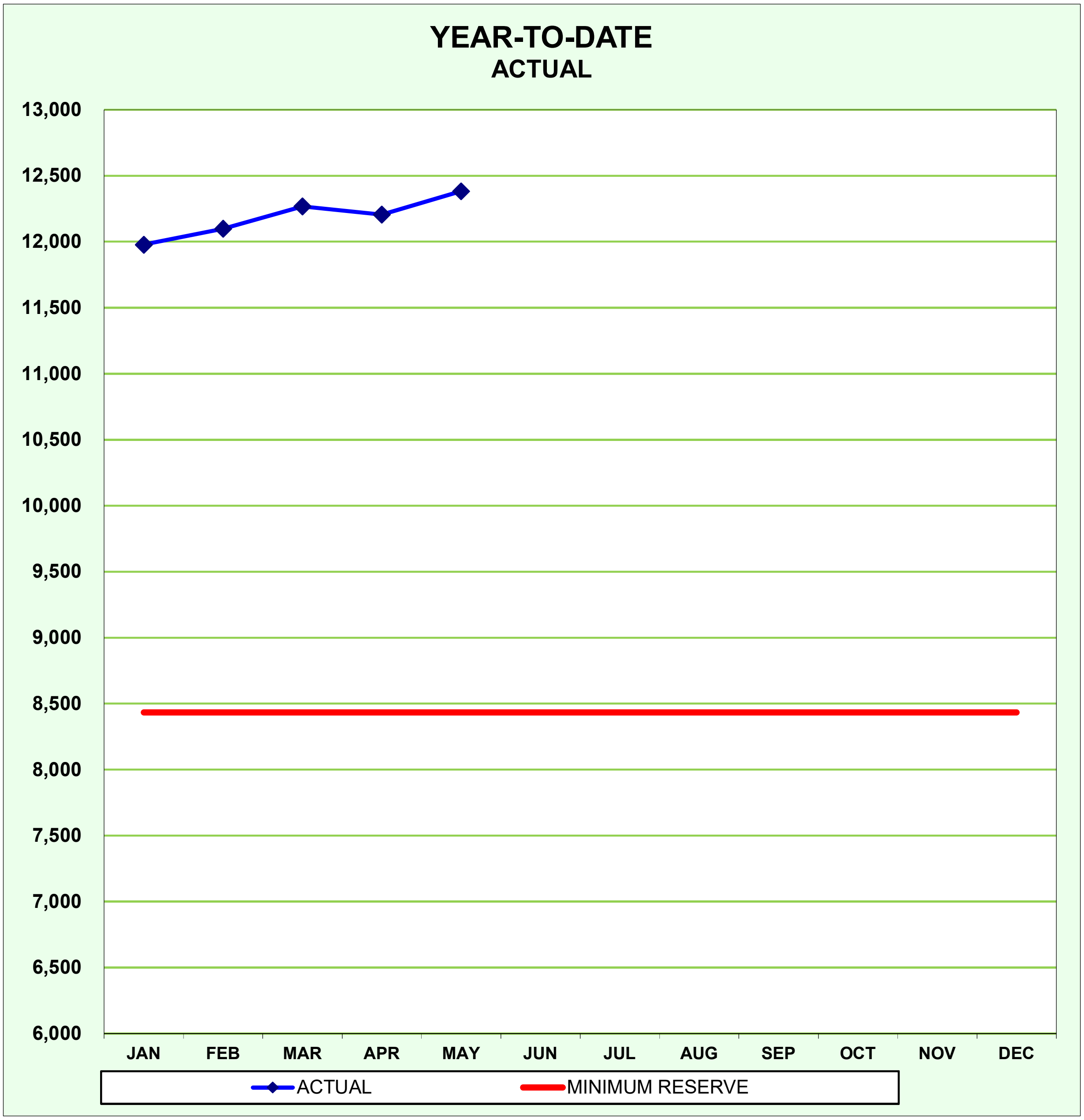
Prior Years Ending Dec 31st		
2020	2019	2018
552,500	567,500	507,000
521,228	322,751	303,726
94.3%	56.9%	59.9%



Attachment: Division Reports June 2021 (13522 : Division Reports & Metrics - June 2021)

CASH AND TEMPORARY INVESTMENTS
WATER

May, 2021



CHANGE IN NET POSITION
WATER

May, 2021