AGENDA
SHAKOPEE PUBLIC UTILITIES COMMISSION
REGULAR MEETING
March 7, 2022
at 5:00 PM

To watch this meeting live click or copy the link: https://tinyurl.com/SPU-YouTube-Live

1. **Call to Order** at 5:00pm in the SPU Service Center, 255 Sarazin Street
   1a) Roll Call

2. **Communications**

3. **Consent Agenda**
   C=> 3a) Approval of February 22, 2022 Minutes (GD)
   C=> 3b) Approval of March 7, 2022 Agenda (KM)
   C=> 3c) March 7, 2022 Warrant List (KW)
   C=> 3d) MMPA February Meeting Update (GD)
   C=> 3e) Res#2022-07 Resolution Approving Payment for the Pipe Oversizing Cost on the Watermain Project: Whispering Waters 1st Addition (JA)

4. **Liaison Report** (JB)

5. **Public Comment Period.** The public comment period provides an opportunity for the public to address the Commission on items that are not on the agenda. Comments should **not** exceed five minutes. The SPU President may adjust that time limit based upon the number of persons seeking to comment. This comment period may not be used to make personal attacks, to air personality grievances, or for political endorsements or campaigns. The public comments are intended for informational purposes only; Commissioners will not enter into a dialogue with commenters, and questions from Commissioners will be for clarification only.

6. **General Manager Report**
   6a) General Manager Report – Verbal (GD)

7. **Reports: Water Items**
   7a) Water System Operations Report – Verbal (LS)
   7b) Bid Results and Estimates for Well 23 (LS)
   7c) City Project 21-001 Maras Street, 13th Avenue, Hansen Avenue Bid Opening Results (JA)

8. **Reports: Electric Items**
   8a) Electric System Operations Report – Verbal (BC)
   8b) MMPA Wholesale Power Contract Review (GD)

9. **Reports: Human Resources**

10. **Reports: General**
    10a) Marketing/Customer Service Report – Verbal (SW)
    10b) Smart Switches Program (GD)

11. **Items for Future Agendas**

12. **Tentative Dates for Upcoming Meetings****
    - March 21, 2022
    - April 4, 2022
    - April 18, 2022

13. **Adjournment**

MINUTES OF THE
SHAKOPEE PUBLIC UTILITIES COMMISSION
FEBRUARY 22, 2022
Regular Meeting

1. Call to Order. President Mocol called the February 22, 2022 meeting of the Shakopee Public Utilities Commission to order at 5:00 PM. President Mocol, Vice President Fox, Commissioner Brennan, and Commissioner Krieg were present.

2. Approval of Consent Agenda. Vice President Fox moved approval of the Consent Agenda: (a) February 7, 2022 Minutes; (b) February 22, 2022 Agenda; (c) February 8, 2022 Warrant List, Account Credit Request/Deposits Refunds; (d) February 22, 2022 Warrant List; (e) Monthly Dashboard as of December 2021; (f) Res#2022-06 Resolution Establishing Electric Rates for Customers Served by Shakopee Public Utilities; (g) 2022 MMPA Transmission Transformed Rate. Commissioner Krieg seconded the motion. Ayes: Mocol, Fox, Brennan, and Krieg. Nays: None. Motion carried.

3. Liaison Report. Commissioner Brennan reported that the City Council reappointed Kathi Mocol for a three-year term. She also noted that the City Council approved the Emblem project.

4. Public Comment Period. No public comments were offered.

5. General Manager Report; MMPA 2021. Greg Drent, General Manager, provided an update on the Virginia Transformer agreement, including an escalation clause and a potentially earlier delivery in October or November. Mr. Drent noted that SPU is working with MVEC to jointly inform customers of the electric service territory exchange. He stated that the April Commission meeting typically includes an election of officers. Mr. Drent noted that he and Commissioner Brennan attended the MMUA virtual Legislative Conference.

6. Water Report. Lon Schemel, Water Superintendent, reported that for Tank #8. the communications company will install communication SCADA equipment and that the filling of that tank should follow. He noted that all preventive maintenance has been completed for the year. Mr. Schemel stated that bids for Well #23 at Tank #8 will be opened on February 28th with recommendations expected to be presented at the March 7th Commission meeting.

7. Electric Report. Brad Carlson, Electrical Superintendent, reported that one outage occurred since the last Commission meeting. He also provided an update on current projects, including tree trimming and underground work for Windermere 5th Addition. Mr. Carlson noted that technical planning work will proceed with MVEC for the transfer of electrical facilities.

8. Customer Service/Marketing Update. Sharon Walsh, Director of Key Accounts/Marketing/ Special Projects, noted that the 2022 Conservation Program started last week. She has been

working with Katama on preparing the initial AMI bid package, which is expected by March 11th. Ms. Walsh noted the SPU electric vehicle will receive its logo. She provided an update on her certification process. She explained that she has coordinated providing information to questions from key accounts as to SPU programs. Ms. Walsh reported that SPU continues to improve the SPU website content and to encourage additional on-line reviews from customers.

9. NISC Contract. Mr. Drent provided an overview of the bid process for the new finance, human resources, and customer billing system. He described how staff narrowed the responses to two candidates, the cost breakdowns, and site visits to two local utilities using each of these software options. Mr. Drent noted that SPU staff had early discussions with the City and determined that the City's system did not support SPU's needs. He presented the staff recommendation to negotiate an agreement with NISC. Vice President Fox moved that the General Manager continue to negotiate an appropriate agreement with NISC and authorize signature. Commissioner Brennan seconded the motion. Ayes: Mocol, Fox, Brennan, and Krieg. Nays: None. Motion carried.

10. SPU Quarterly Investment Performance Review/Economic & Market Update. Kelley Willemssen, Director of Finance & Administration, introduced Brian Johnson and Danny Nelson from PFM Asset Management Group, SPU's Investment Advisor. They presented an update on current market conditions and provided an overview of how SPU's portfolio has performed during the past quarter and what is expected for the remainder of the year.

11. Water and Electric Projects Update, Joseph Adams, Planning and Engineering Director, presented the 2022 current SPU water and electric projects, as well as projects by the City, County, and developers that affect SPU utilities.

12. Future Items. Commissioner Brennan requested information on smart switches.

13. Adjourn. Motion by Vice President Fox, seconded by Commissioner Krieg, to adjourn to the Monday, March 7, 2022 meeting. Ayes: Mocol, Fox, Brennan, and Krieg. Nays: None. Motion carried.

Greg Drent, Commission Secretary

Proposed As Consent Item **3b**

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SHAKOPEE PUBLIC UTILITIES COMMISSION
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4. **Liaison Report** (JB)

5. **Public Comment Period.** The public comment period provides an opportunity for the public to address the Commission on items that are not on the agenda. Comments should **not** exceed five minutes. The SPU President may adjust that time limit based upon the number of persons seeking to comment. This comment period may not be used to make personal attacks, to air personality grievances, or for political endorsements or campaigns. The public comments are intended for informational purposes only; Commissioners will not enter into a dialogue with commenters, and questions from Commissioners will be for clarification only.

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    - March 21, 2022
    - April 4, 2022
    - April 18, 2022

13. **Adjournment**

Proposed As Consent Item 3c

SHAKOPEE PUBLIC UTILITIES COMMISSION

WARRANT LISTING

March 7, 2022

By direction of the Shakopee Public Utilities Commission, the Secretary does hereby authorize the following warrants drawn upon the Treasury of Shakopee Public Utilities Commission:

Deputy Registrar #135	$0.00
Verizon Wireless	$1,556.64
Principal Financial Group	$3,384.40
U.S. Postal Service	$398.00
ABDO LLP	$27,060.00
ALLSTREAM BUSINESS US, INC	$2,476.84
AMARIL UNIFORM CO.	$5,021.55
AMERICAN ENGINEERING TESTING INC	$2,500.00
ANDREA AMANDA RAMNAUTH	$3,933.32
APPLE FORD OF SHAKOPEE	$78.09
ARAMARK REFRESHMENT SERVICES INC	$649.56
ASPEN EQUIPMENT CO	$279.80
BARTUSEK, RON	$23.00
BAUMANN, BERNARD	$50.00
BERNDTSON, ROBERT	$580.12
BORDER STATES ELECTRIC SUPPLY INC	$2,340.86
BRAUN INTERTEC CORP.	$492.50
BRUCKNER MOLLY	$75.00
CALDWELL TANK, INC.	$10,646.74
CDW LLC	$1,910.04
CHOICE ELECTRIC INC	$42,808.30
CITY OF SHAKOPEE	$583,757.12
CITY OF SHAKOPEE	$385.00
CITY OF SHAKOPEE	$1,031.08
CM CONSTRUCTION COMPANY	$22,536.76
COMCAST CABLE COMMUNICATIONS, INC.	$2.25
CONCRETE CUTTING & CORING INC	$46.41
DAILY PRINTING, INC.	$211.51
DEL'S CONSTRUCTION COMPANY INC.	$32,517.74
DELTA DENTAL PLAN OF MN	$5,463.21
DEWAELE, JEFFREY & KIRSTEN	$50.00
DEWILD GRANT RECKERT AND ASSOCIATES	$116.00
DICK'S/LAKEVILLE SANITATION INC	$310.05
FASTENAL IND & CONST SUPPLIES	$394.85
FERGUSON US HOLDINGS, INC.	$11,319.64
FIELDSETH, JAMES	$70.00
FILTRATION SYSTEMS, INC	$915.92
FURTHER	$7,349.44
GENERAL SECURITY SERVICES CORP	$442.92
GRAINGER	$347.88
GRAYBAR ELECTRIC COMPANY INC	$500.27
GURSTEL LAW FIRM PC	$198.27
HARRIS ST PAUL., INC	$21,342.51
HAWKINS INC	$2,099.76
HD SUPPLY FACILITIES MAINTENANCE LTD	$138.05
HEALTHPARTNERS	$80,329.07
IDEAL SERVICE CO, INC.	$1,562.50
INDELCO PLASTICS CORP	$291.30
INDUSTRIAL FABRICATION SERVICES, INC	$3,386.07
INNOVATIVE OFFICE SOLUTIONS LLC	$11.59
IRBY - STUART C IRBY CO	$918.06
IRBY TOOL & SAFETY	$3,524.53
J&W ASPHALT, ING	$1,035.50
KAHLE, MATTHEW	$19.00
KEITH, EVERETT	$75.00
KIMLEY-HORN AND ASSOCIATES, INC.	$10,975.00
LILLESTOL, CODY & JESSICA	$500.00
LOCATORS & SUPPLIES INC	$288.40
MARCHAND, PEGGY ANN	$500.00
MILSOFT UTILITY SOLUTIONS, INC.	$26,969.91
MINN VALLEY TESTING LABS INC	$436.00
MINNESOTA LIFE	$1,427.63
MOM'S LANDSCAPING & DESIGN LLC	$14,800.33
MONGARE, JOSHUA	$500.00
MRA-THE MANAGEMENT ASSOCIATION	$166.00
NAPA AUTO PARTS	$402.07
NCPERS GROUP LIFE INSURANCE	$176.00
NEVILLE, GERRY	$279.45
NGUYEN, LOC H	$500.00
NICKOLAY, CINDY	$198.60
NORTH COUNTRY CONCRETE, INC.	$6,014.00
NORTHERN TOOL & EQUIPMENT CO.	$149.95
NOVA FIRE PROTECTION, INC.	$20,431.65
O'BRIEN, TYLER	$88.30
Principal Financial Group	$7,880.75
PALMER WEST CONSTRUCTION CO INC	$7,617.17
PEARSON, MACHELLE	$340.00
PIERRE, DANIEL	$16.98
PITNEY BOWES INC	$1,214.52
POMP'S TIRE SERVICE INC	$1,491.80
RAGHAVEN, BIJOY	$500.00
RAVI, PRASHANTH BHASKER	$125.00
REICHEL PAINTING CO., INC.	$17,000.00
RESCO	$3,141.90
SAMBATEK	$15,379.00

SHAKOPEE PUBLIC UTILITIES COMMISSION

WARRANT LISTING

March 7, 2022

By direction of the Shakopee Public Utilities Commission, the Secretary does hereby authorize the following warrants drawn upon the Treasury of Shakopee Public Utilities Commission:

SCHERER BROTHERS	$68.14
SCHINTZ, JACK	$122.27
SCHOENECKER, DOUGLAS	$500.00
SCOTT COUNTY RECORDERS OFFICE	$92.00
SHAKOPEE TOWING INC	$402.66
ST PETER INSULATED GLASS INC	$462.50
STOCKER, JORDAN	$14.76
TRIPLETT, GREG	$366.78
VANKAYALA, SATHISH	$15.00
VERIZON CONNECT FLEET USA LLC	$523.95
WESCO DISTRIBUTION INC	$952.68
ZIEGLER INC	$8,434.18
ZIMMERMAN, ERIK	$500.00
	$1,040,929.35

Presented for approval by: Director of Finance & Administration

Approved by General Manager

Approved by Commission President

SHAKOPEE PUBLIC UTILITIES COMMISSION

WARRANT LISTING

March 7, 2022

By direction of the Shakopee Public Utilities Commission, the Secretary does hereby authorize the following warrants drawn upon the Treasury of Shakopee Public Utilities Commission:

Deputy Registrar #135	$0.00	VOID
Verizon Wireless	$1,556.64	12/24-1/23/22 - check on demand
Principal Financial Group	$3,384.40	Jan. L.T.D. premium - check on demand
U.S. Postal Service	$398.00	P.O. Box 470 Annual renewal fee - check on demand
ABDO LLP	$27,060.00	Accounting Service thru 2/28/22
ALLSTREAM BUSINESS US, INC	$2,476.84	Shak Sub, Pike Lake, S.Sub, and SPU
AMARIL UNIFORM CO.	$5,021.55	F.R. clothing for Electric dept. employees
AMERICAN ENGINEERING TESTING INC	$2,500.00	WO#2377 - Soil Resistivity Testing
ANDREA AMANDA RAMNAUTH	$3,933.32	March building services
APPLE FORD OF SHAKOPEE	$78.09	standard oil change Water dept. #650
ARAMARK REFRESHMENT SERVICES INC	$649.56	Coffee for lunchrooms
ASPEN EQUIPMENT CO	$279.80	Cutting Ed
BARTUSEK, RON	$23.00	Water Op. renewal reimb.
BAUMANN, BERNARD	$50.00	2022 Res. Energy Star Appliance Rebate
BERNDTSON, ROBERT	$580.12	Mileage reimbursement and Boot allowance reimb.
BORDER STATES ELECTRIC SUPPLY INC	$2,340.86	PCB Chlor D Tect, Load break phase 3, anchor, arrester, fuse fitall
BRAUN INTERTEC CORP.	$492.50	WO#2470 - Prof. service thru 1/7/22
BRUCKNER MOLLY	$75.00	2022 Res. Energy Star Appliance Rebate
CALDWELL TANK, INC.	$10,646.74	WO#2259 - Tank #8 Pay Request #12 thru Feb.
CDW LLC	$1,910.04	Monitors for Eng.
CHOICE ELECTRIC INC	$42,808.30	WO#2470 - $42549.55 Draw #5 and $258.75-Remove & Install Saver switchs
CITY OF SHAKOPEE	$583,757.12	Jan. & Feb. 2021 True Up - PILOT ($272757.12) and 2022 True up ($311,000.00)
CITY OF SHAKOPEE	$385.00	R.O.W. Permits
CITY OF SHAKOPEE	$1,031.08	Feb. Storm drainage/SPU Properties
CM CONSTRUCTION COMPANY	$22,536.76	WO#2470 - Draw #6
COMCAST CABLE COMMUNICATIONS, INC.	$2.25	Feb. Cable for lunchroom
CONCRETE CUTTING & CORING INC	$46.41	Chain loop
DAILY PRINTING, INC.	$211.51	Business Card - 1 name
DEL'S CONSTRUCTION COMPANY INC.	$32,517.74	WO#2470 -Retainage Request Draw#5/Draw #1, Retainage Request #2, Jan. SPU construction
DELTA DENTAL PLAN OF MN	$5,463.21	Feb. Dental premiums
DEWAELE, JEFFREY & KIRSTEN	$50.00	2022 Res. Energy Star Appliance Rebate
DEWILD GRANT RECKERT AND ASSOCIATES	$116.00	Dean Lake #2 Circuit Switcher Replace
DICK'S/LAKEVILLE SANITATION INC	$310.05	March Garbage service
FASTENAL IND & CONST SUPPLIES	$394.85	Elec. dept. tools
FERGUSON US HOLDINGS, INC.	$11,319.64	Repair versaprobes ($1360.84), WO#2451 - $6730.87 - Meter horns, Cored pug, brs bush, pipe
FIELDSETH, JAMES	$70.00	2022 Res. Energy Star Lighting
FILTRATION SYSTEMS, INC	$915.92	HVAC Filters
FURTHER	$7,349.44	Flex dependent care reimb.
GENERAL SECURITY SERVICES CORP	$442.92	NVR Ext. warranty 2/1/22-4/30/22
GRAINGER	$347.88	Label Replacement stickers & wet mop handle
GRAYBAR ELECTRIC COMPANY INC	$500.27	Cable to run from rear garage to computer room
GURSTEL LAW FIRM PC	$198.27	Final payoff for M.E. Garn
HARRIS ST PAUL., INC	$21,342.51	WO# 2470 - plumbing & Retainage
HAWKINS INC	$2,099.76	Chlorine Cylinder
HD SUPPLY FACILITIES MAINTENANCE LTD	$138.05	Pocket Thermometer
HEALTHPARTNERS	$80,329.07	Feb. Health ins. premiums
IDEAL SERVICE CO, INC.	$1,562.50	Troubleshot a fault well #13
INDELCO PLASTICS CORP	$291.30	Tube, connectors
INDUSTRIAL FABRICATION SERVICES, INC	$3,386.07	#2470 - Work done on SPUC
INNOVATIVE OFFICE SOLUTIONS LLC	$11.59	Name Plate for Kelley
IRBY - STUART C IRBY CO	$918.06	COPPER
IRBY TOOL & SAFETY	$3,524.53	LittleMule, testing of new blankets, fluke , clamp meters
J&W ASPHALT, ING	$1,035.50	WO#2470 - Final invoice on grading & Paving
KAHLE, MATTHEW	$19.00	D.L. Renewal difference for CDL license
KEITH, EVERETT	$75.00	2022 Res. Energy Star Appliance Rebate
KIMLEY-HORN AND ASSOCIATES, INC.	$10,975.00	WO#2360 - Service rendered 83 Water main design
LILLESTOL, CODY & JESSICA	$500.00	2022 Res. Cooling & Heating
LOCATORS & SUPPLIES INC	$288.40	Safety Vests
MARCHAND, PEGGY ANN	$500.00	2022 Res. Cooling & Heating
MILSOFT UTILITY SOLUTIONS, INC.	$26,969.91	CIS Support 3/22-2/23

SHAKOPEE PUBLIC UTILITIES COMMISSION

WARRANT LISTING

March 7, 2022

By direction of the Shakopee Public Utilities Commission, the Secretary does hereby authorize the following warrants drawn upon the Treasury of Shakopee Public Utilities Commission:

MINN VALLEY TESTING LABS INC	$436.00	Coliform, Nitrate & Nitrite
MINNESOTA LIFE	$1,427.63	Feb. Life Ins. Premiums
MOM'S LANDSCAPING & DESIGN LLC	$14,800.33	WO#2470 - Progress pymt for landscaping/contract
MONGARE, JOSHUA	$500.00	2022 Res. Cooling & Heating
MRA-THE MANAGEMENT ASSOCIATION	$166.00	background check for A.S.
NAPA AUTO PARTS	$402.07	Anti freeze for vactron, sea foam
NCPERS GROUP LIFE INSURANCE	$176.00	Life Ins. premiums for March
NEVILLE, GERRY	$279.45	Mileage reimbursement
NGUYEN, LOC H	$500.00	2022 Res. Energy Star Appliance Rebate
NICKOLAY, CINDY	$198.60	Mileage reimbursement
NORTH COUNTRY CONCRETE, INC.	$6,014.00	WO#2470 - Draw 2 & Retainage
NORTHERN TOOL & EQUIPMENT CO.	$149.95	Chargers
NOVA FIRE PROTECTION, INC.	$20,431.65	WO#2470 - Application #1
O'BRIEN, TYLER	$88.30	Metering School reimb.
Principal Financial Group	$7,880.75	Feb. L.T.D. Premiums
PALMER WEST CONSTRUCTION CO INC	$7,617.17	WO#2470 - Retainage Request
PEARSON, MACHELLE	$340.00	1st Qtr. onsite collections for drug testing
PIERRE, DANIEL	$16.98	DVD Cases for recording commission mtg.
PITNEY BOWES INC	$1,214.52	1st Qtr. rental
POMP'S TIRE SERVICE INC	$1,491.80	Trailer tires, steer tire replacement and track tires
RAGHAVEN, BIJOY	$500.00	2022 Res. Cooling & Heating
RAVI, PRASHANTH BHASKER	$125.00	2022 Res. Energy Star Appliance Rebate
REICHEL PAINTING CO., INC.	$17,000.00	WO#2470 - Painting at SPU building
RESCO	$3,141.90	ANCHOR, Metering cable,heat shrink, tran current bar, cutout
SAMBATEK	$15,379.00	WO#2041 - ($3844.50) Prof. service thru 2/12/22 Windermere Booster Station, WO#2259 - ($11534.50) - Eleveated Water Tank #8
SCHERER BROTHERS	$68.14	Expanding Foam Sealant & Concrete mix
SCHINTZ, JACK	$122.27	Metering School reimb.
SCHOENECKER, DOUGLAS	$500.00	2022 Res. Cooling & Heating
SCOTT COUNTY RECORDERS OFFICE	$92.00	Easement for VA CBOC Properties LLC & Water capacity charge for Shakopee Apartments LLC
SHAKOPEE TOWING INC	$402.66	2018 International Tow/Hook fee
ST PETER INSULATED GLASS INC	$462.50	WO#2470 - Retainage Request
STOCKER, JORDAN	$14.76	Metering School reimb.
TRIPLETT, GREG	$366.78	Mileage reimbursement
VANKAYALA, SATHISH	$15.00	2022 Res. Energy Star Lighting
VERIZON CONNECT FLEET USA LLC	$523.95	Vehicle work - Feb. Charge
WESCO DISTRIBUTION INC	$952.68	Orange traffic cones w/reflective collar
ZIEGLER INC	$8,434.18	T-12D Drop Deck Trailer
ZIMMERMAN, ERIK	$500.00	2022 Res. Cooling & Heating
	$1,040,929.35	

Kelly Williamson

Presented for approval by: Director of Finance & Administration

Approved by General Manager

Approved by Commission President

Proposed As Consent Item 3d

Shakopee Public Utilities

PO Box 470 • 255 Sarazin Street
Shakopee, Minnesota 55379
Main 952.445-1988 • Fax 952.445-7767
www.shakopeeutilities.com

To: SPU Commissioners

From: Greg Drent, General Manager

Date: March 1, 2022

Subject: MMPA February Meeting Update

The Board of Directors of the Minnesota Municipal Power Agency (MMPA) met on February 22, 2022, at Chaska City Hall in Chaska, Minnesota and via videoconference.

The Board reviewed the Agency's financial and operating performance for January 2022.

The Board discussed COVID-19 and its effects on supply chains and labor markets.

The Board engaged in a long-term planning session on solar investment.

The Board discussed the Agency's energy education programs for academic year 2021-2022, which include an elementary program for 4th graders and a high school program. Virtual program offerings are being provided to schools this year because of the pandemic.

There was an increase of 4 customers participating in MMPA's residential Clean Energy Choice program from December to January. Customer penetration of the program for residential customers remains at 3.8%.

Thanks

Proposed As Consent Item 3e

RESOLUTION #2022-07

RESOLUTION APPROVING PAYMENT FOR THE
PIPE OVERSIZING COSTS ON THE WATERMAIN PROJECT:

WHISPERING WATERS 1ST ADDITION

WHEREAS, the Shakopee Public Utilities Commission had previously approved of an estimated amount of $20,000.00 with Resolution #2021-13 for oversizing on the above described watermain project, and

WHEREAS, the pipe sizes required for that project have been installed as shown on the engineering drawing by Probe Engineering Company Inc, and

WHEREAS, a part, or all, of the project contains pipe sizes larger than would be required under the current Standard Watermain Design Criteria as adopted by the Shakopee Public Utilities Commission, and

WHEREAS, the policy of the Shakopee Public Utilities Commission calls for the payment of these costs to install oversize pipe above the standard size.

NOW THEREFORE, BE IT RESOLVED, that the payment by the Shakopee Public Utilities Commission for the oversizing on this project is approved in the amount of $22,969.92, and

BE IT FURTHER RESOLVED, that all things necessary to carry out the terms and purpose of this Resolution are hereby authorized and performed.

Passed in regular session of the Shakopee Public Utilities Commission, this 7th day of March, 2022.

_____
Commission President: Kathi Mocol

ATTEST:

_____
Commission Secretary: Greg Drent

Shakopee Public Utilities

PO Box 470 • 255 Sarazin Street
Shakopee, Minnesota 55379
Main 952.445-1988 • Fax 952.445-7767
www.shakopeeutilities.com

TO: Greg Drent, General Manager

FROM: Lon R. Schemel, Water Superintendent

SUBJECT: Bid Results and Estimates for Well 23

DATE: March 3, 2022

On February 28, 2022, at 2 pm, sealed bids were opened for the construction of water Well 23 located at the Tank 8 site. There were 3 qualified bidders: Traut Companies out of Waite Park, E. H. Renner out of Elk River, and Mineral Service Plus out of Green Isle, MN.

The Engineer's estimate for construction is $651,650.00. Funding for the well is coming from the Connection Fund with the budgeted amount of $727,000.00. Traut Companies is the low bidder with a bid of $389,209.00. Estimated engineering for the project is $89,980.00 bringing the project to $479,189.00 which is $247,811.00 under budget.

Paul Herubin, Project Engineer from Sambatek is in attendance this evening to answer any questions that the Commission may have. Staff requests that the Commission award the project to Traut Companies.

March 1, 2022

Honorable Chairman and Members of the Commission
c/o Lon Schemel, Water Superintendent
Shakopee Public Utility
255 Sarazin Street
Shakopee, MN 55379

Subject: Contractor Bid Award Recommendation
Well No. 23, SPU, Shakopee

Dear Mr. Schemel,

On Monday February 28, 2022 a bid opening was held for the Well No. 23. Three bids were received and Traut Companies was the apparent low bidder:

The three bids received are listed below:

	TOTAL BID
Traut Companies:	$389,209.00
EH Renner:	$394,345.00
Mineral Service Plus:	$464,703.70

All the bids were totaled and checked. The Traut Companies bid was verified as the low bid. Bid submittal documentation was reviewed and was found to be acceptable.

The separation between the three lowest bids is representative of a very competitive group of bids and is a good indication of competitive bidding between the three drilling companies.

The Engineer's construction cost estimate was $651,650.00 and was high by $262,441.00. This suggests that the manufacturing and labor supply chains may be stabilizing somewhat.

Based on our review of the lowest apparent bid the recommendation is to award the Project to Traut Companies.

Feel free to contact me with any questions and comments.

Sincerely,
Sambatek, Inc.

Paul Herubin, PE
Project Manager

Enclosures; Bid Opening Tabulation, Plan Holder's List

BID OPENING TABULATION

PROJECT: Well No. 23
DATE: Monday February 28, 2022
PLACE: SPU Service Center
ENGINEER: Sambatek Inc., Paul Herubin

TIME: 2:00 P.M.
OWNER: Shakopee Public Utilities

Contractor	Addendum Sent	Proposal Guarantee (5% Bond)	Total Amount of Bid
Traut	Yes	Yes	$389,209.00
Mineral Service plus	yes	yes	$464,703.70
E.H. Renner	Yes	Yes	$394,345.00

Plan Holder Report as of 03/01/2022 11:14 AM CST

Shakopee Public Utilities - Water Well No. 23

Quest eBidDoc™ Number: 8110212

Closing Date: Mon, 02/28/2022 02:00 PM CST
Posting Type: Construction Project
Owner Name: Shakopee Public Utilities
Solicitor Name: Sambatek
Contact: Paul Herubin
Phone: 651-788-6706
Email: pherubin@sambatek.com

Company	Address	Contact	Email Address	Phone	Fax	Business Certification	Business Designation	Entry Date	Document Type	Comments
E H Renner & Sons, Inc. Well Drilling	15688 Jarvis Street NW, Elk River, MN-55330	Roger Renner	krenner@ehrenner.com	763-427-6100		SBE	Prime Bidder	01/25/2022	eBidDoc	
Minnesota Builders Exchange	1123 Glenwood Ave, Minneapolis, MN-55405	Tom Getzke	addenda@mbex.org	612-381-2625			Plan Room	01/25/2022	eBidDoc	
TRAUT COMPANIES	141 28th Avenue South, Waite Park, MN-56387-0547	Kelli Commerford	kellic@trautcompanies.com	320-251-5090	320-259-0594		Prime Bidder	01/26/2022	eBidDoc	
ConstructConnect	3825 Edwards Rd, Cincinnati, OH-45209	Eric Mills	content@constructconnect.com	800-364-2059	866-570-8187		Plan Room	01/27/2022	eBidDoc	

Company	Address	Contact	Email Address	Phone	Fax	Business Certification	Business Designation	Entry Date	Document Type	Comments
Dodge Data & Analytics Next Member Numbe	2860 S State Hwy 161, Grand Prairie, TX-75052	DodgeAPI	dodge.docs@construction.com	513.666.3354	800-768-5594		NOT BIDDING	01/31/2022	eBidDoc	
Mineral Service Plus, LLC	16409 - 371st Avenue, Green Isle, MN-55338	Nick Milbrandt	nickm@mineralserviceplus.com	320-238-0195	320-238-0198	SBE	Prime Bidder	02/01/2022	eBidDoc	
Keys Well Drilling Company	1156 Homer Street, St Paul, MN-55116-3232	Nadine Kelly	nadinek@keyswell.com	651-646-7871	651-641-0216		Other	02/01/2022	eBidDoc	

ARTICLE 5 - BASIS OF BID
Bid Form Tabulation Spread Sheet

	ITEM	QUANTITY			UNIT PRICE		ENGINEER ESTIMATE TOTAL	TRAUT UNIT PRICE	TRAUT UNIT	TRAUT TOTAL	EH RENNER UNIT PRICE	EH RENNER UNIT	EH RENNER TOTAL	MINERAL SERVICE UNIT PRICE	MINERAL SERVICE UNIT	MINERAL SERVICE TOTAL
	PART A - WATER WELL NO. 23															
1	Mobilization and Demobilization	1	LS		$61,000.00	LS	$61,000.00	$25,130.00	LS	$25,130.00	$33,000.00	LS	$33,000.00	$12,500.00	LS	$12,500.00
2	24-inch Casing	187	LF	@	$535.00	/LF	$100,045.00	$290.00	LF	$54,230.00	$295.00	LF	$55,165.00	$175.00	LF	$32,725.00
3	23-inch open hole	137	LF	@	$225.00	/LF	$30,825.00	$195.00	LF	$26,715.00	$180.00	LF	$24,660.00	$165.00	LF	$22,605.00
4	Install 18-inch liner pipe	324	LF	@	$215.00	/LF	$69,660.00	$135.00	LF	$43,740.00	$170.00	LF	$55,080.00	$125.00	LF	$40,500.00
5	Neat cement grout	20	CY	@	$675.00	/CY	$13,500.00	$725.00	CY	$14,500.00	$515.00	CY	$10,300.00	$560.00	CY	$11,200.00
6	17-inch open hole	98	LF	@	$195.00	/EA	$19,110.00	$125.00	LF	$12,250.00	$48.00	LF	$4,704.00	$95.00	LF	$9,310.00
7	Explosives including accessories & blasting	250	LB	@	$50.00	/LB	$12,500.00	$55.00	LB	$13,750.00	$45.00	LB	$11,250.00	$28.00	LB	$7,000.00
8	Well sandstone removal	500	CY	@	$145.00	/CY	$72,500.00	$115.00	CY	$57,500.00	$125.00	CY	$62,500.00	$400.00	CY	$200,000.00
9	Temporary well development and settling basin sediment removals	1	LS		$20,000.00	LS	$20,000.00	$1,200.00	LS	$1,200.00	$12,000.00	LS	$12,000.00	$10,000.00	LS	$10,000.00
10	Initial set up of equipment for air surging and removal	1	LS		$9,500.00	LS	$9,500.00	$7,500.00	LS	$7,500.00	$10,000.00	LS	$10,000.00	$3,000.00	LS	$3,000.00
11	Additional set up of equipment for air surging and removal	1	EA	@	$3,500.00	/EA	$3,500.00	$125.00	EA	$125.00	$500.00	EA	$500.00	$3,000.00	EA	$3,000.00
12	Develop well by air surging	150	HR	@	$500.00	/HR	$75,000.00	$400.00	HR	$60,000.00	$285.00	HR	$42,750.00	$275.00	HR	$41,250.00
13	Initial set up for test pump and removal	1	LS		$9,500.00	LS	$9,500.00	$7,500.00	LS	$7,500.00	$8,000.00	LS	$8,000.00	$7,000.00	LS	$7,000.00
14	Additional set up for test pump and removal	1	EA	@	$2,500.00	/EA	$2,500.00	$125.00	EA	$125.00	$500.00	EA	$500.00	$5,000.00	EA	$5,000.00
15	Operate test pump	140	HR	@	$350.00	/HR	$49,000.00	$180.00	HR	$25,200.00	$190.00	HR	$26,600.00	$174.00	HR	$24,360.00
16	Discharge pipe	800	LF	@	$50.00	/LF	$40,000.00	$5.00	LF	$4,000.00	$8.00	LF	$6,400.00	$5.00	LF	$4,000.00
17	Disinfect well	1	LS		$2,000.00	LS	$2,000.00	$125.00	LS	$125.00	$350.00	LS	$350.00	$350.00	LS	$350.00
18	Televise and gamma log well	1	LS		$4,000.00	LS	$4,000.00	$3,200.00	LS	$3,200.00	$3,600.00	LS	$3,600.00	$3,600.00	LS	$3,600.00
19	Sand content analysis	1	EA	@	$150.00	/EA	$150.00	$125.00	EA	$125.00	$25.00	EA	$25.00	$200.00	EA	$200.00
20	Chemical analysis by laboratory	1	EA	@	$2,500.00	/EA	$2,500.00	$2,495.00	EA	$2,495.00	$3,850.00	EA	$3,850.00	$1,450.00	EA	$1,450.00
21	Bacteriological well test	1	EA	@	$300.00	/EA	$300.00	$125.00	EA	$125.00	$25.00	EA	$25.00	$300.00	EA	$300.00
22	Well development blasting and monitoring report	1	LS		$1,200.00	LS	$1,200.00	$6,800.00	LS	$6,800.00	$4,250.00	LS	$4,250.00	$350.00	LS	$350.00
23	Furnish two (2) dataloggers	2	EA		$2,500.00	/EA	$5,000.00	$375.00	EA	$750.00	$125.00	EA	$250.00	$500.00	EA	$1,000.00
	SUBTOTAL PART A - WATER WELL NO. 23						**$603,290.00**			**$367,085.00**			**$375,759.00**			**$440,700.00**
	PART B - SITE WORK															
1	Site Clearing and Preparation	1	LS	@	$15,000.00	LS	15,000.00	$2,300.00	LS	$2,300.00	$1,950.00	LS	$1,950.00	$2,000.00	LS	$2,000.00
2	Erosion control silt fence	1200	LF	@	$10.00	LF	12,000.00	$5.00	LF	$6,000.00	$4.00	LF	$4,800.00	$2.40	LF	$2,880.00
3	Temporary Grass Seed and Mulch	0.51	AC	@	$1,000.00	AC	510.00	$4,400.00	AC	$2,244.00	$4,600.00	AC	$2,346.00	$3,120.00	AC	$1,591.20
	SUBTOTAL PART B - SITE WORK						**$27,510.00**			**$10,544.00**			$9,096.00			**$6,471.20**
	PART C - ACCESS DRIVEWAY															
1	Access Driveway Subgrade Grading	150	FT	@	$30.00	FT	$4,500.00	$18.00	FT	$2,700.00	$6.00	FT	$900.00	$10.00	FT	$1,500.00
2	Access Driveway Aggregate Base	90	TON	@	$35.00	TON	$3,150.00	$30.00	TON	$2,700.00	$19.00	TON	$1,710.00	$40.25	TON	$3,622.50
3	Access Driveway Grading Maintenance	1000	FT	@	$10.00	FT	$10,000.00	$4.00	FT	$4,000.00	$6.00	FT	$6,000.00	$10.00	FT	$10,000.00
4	Access Driveway Aggregate Maintenance	40	TON	@	$40.00	TON	$1,600.00	$36.50	TON	$1,460.00	$6.00	TON	$240.00	$40.25	TON	$1,610.00
5	Access Driveway Aggregate Removal	40	TON	@	$40.00	TON	$1,600.00	$18.00	TON	$720.00	$16.00	TON	$640.00	$20.00	TON	$800.00
	SUBTOTAL PART C - ACCESS DRIVEWAY						**$20,850.00**			**$11,580.00**			$9,490.00			**$17,532.50**
	TOTAL BID - WATER WELL NO. 23						**$651,650.00**			**$389,209.00**			**$394,345.00**			**$464,703.70**

SPU
Shakopee Public Utilities

PO Box 470 • 255 Sarazin Street
Shakopee, Minnesota 55379
Main 952.445-1988 • Fax 952.445-7767
www.shakopeeutilities.com

TO: Greg Drent, General Manager

FROM: Joseph D. Adams, Planning & Engineering Director

SUBJECT: City Project No. 21-001 Maras Street, 12th Avenue, Hanson Avenue

DATE: March 3, 2022

ISSUE

This is to advise the Utilities Commission that the subject project will have a bid opening on Friday March 4, 2022.

BACKGROUND

The subject project will include the installation of a 12-inch diameter water main that will serve the industrial zoned area east of Stagecoach Road and south of 13th Avenue. The project includes an interconnection with the City of Savage water system at the east end of 13th Avenue at the cities' boundary.

DISCUSSION

Staff has been in contact with city of Savage water department staff to coordinate the interconnection and a construction cooperative agreement is being developed for the city of Shakopee's contractor to work in the city of Savage right of way to install the interconnection facilities. It is important to note the interconnection facilities cost will be split equally between SPU and the city of Savage as it is being installed to the mutual benefit of both parties. And SPU's share of the cost will be funded out of the trunk water main fund and not be a component of the property owner's costs to be recovered via a lateral water main charge at the time of water service being connected to each individual parcel.

RECOMMENDATION

Staff will present the bid results at the Commission meeting. Staff is recommending the Commission indicate by motion their support for the City Council to award the construction contract at the March 8th Council meeting.

8b

SPU
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Shakopee, Minnesota 55379
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www.shakopeeutilities.com

DATE: March 3, 2022

TO: SPU Commissioners

FROM: Greg Drent, General Manager

Subject: MMPA wholesale power contract

Shakopee Public Utilities has been a member of the Minnesota Municipal Power Agency (MMPA) since 2004. MMPA is responsible for providing energy to all SPU substations at the transmission voltage. SPU owns the substation transformer, transforms the transmission voltage down to distribution voltage, and delivers power to our retail customers. MMPA has 12 member communities and has monthly board meetings where each community has a board seat.

MMPA's mission is to provide reliable, competitively priced power to its members and to create value for both the Agency and its members. The Agency takes a long-term approach to power supply planning that includes a diversified portfolio of owned and purchased generation containing both conventional and renewable resources to deliver on its mission. In addition to supplying reliable power, MMPA is committed to supporting the communities it serves. The Agency accomplishes this by offering Energy Education Programs, developing local power generation in member communities, providing conservation and renewable energy programs to members and customers, and converting waste from our member communities into a valuable energy source at the Hometown BioEnergy facility.

Through MMPA membership, each community has a voice in making important decisions affecting their communities' energy future. Members benefit from MMPA's collective strength in producing, buying, and selling electrical power. MMPA strives to provide reliable, affordable, and sustainable energy to its communities. Each member community benefits through representation on MMPA's Board of Directors. The board shapes strategy and makes important policy decisions on energy for each hometown. MMPA is considering many renewable projects in the future, and there will be bonding requirements when these projects come. MMPA will be asking member communities to participate in these projects and sign up for an extension on their MMPA wholesale contract.

Attached is the MMPA wholesale contract and MMPA integrated resource plan from 2018.

Action:

No action required as this is information only

CERTIFICATION

STATE OF MINNESOTA)
COUNTY OF SCOTT)
CITY OF SHAKOPEE)

I hereby certify that the attached Resolution No. 754 is a true and correct copy of the Resolution presented to and adopted by the Shakopee Public Utilities Commission at a duly called meeting held on the 11th day of February, 2004 and that the same has not been rescinded or amended and is in full force and effect.

Jerry Fox

Jerry Fox 4/12/04

Secretary
Shakopee Public Utilities Commission

SHAKOPEE PUBLIC UTILITIES COMMISSION

Resolution No. 754

A RESOLUTION REQUESTING MEMBERSHIP IN THE MINNESOTA MUNICIPALPOWER AGENCY, ACCEPTING THE PROVISIONS OF THE AGENCY AGREEMENT AND BY-LAWS OF THE MINNESOTA MUNICIPAL POWER AGENCY, APPOINTING A REPRESENTATIVE TO THE AGENCY AND REQUESTING THE CONCURRENCE OF THE CITY COUNCIL

NOW THEREFORE BE IT RESOLVED BY THE PUBLIC UTILITIES COMMISSION OF THE CITY OF SHAKOPEE :

Section 1. It is hereby found, determined and declared that:

A. The Minnesota Municipal Power Agency (the "Agency") was created and declared effective by the Minnesota Secretary of State on May 19, 1992, as authorized and provided in Minnesota Statutes, Chapter 453 (the "Agency Statute").

B. The following Minnesota cities are the present members (the "Members") of the Agency: Anoka, Arlington, Brownton, Chaska, Le Sueur, North St. Paul, Olivia and Winthrop and they each purchase wholesale power, transmission and other electric utility services from the Agency .

C. The City of Shakopee is authorized by Minnesota Statutes, sections 412.321 through 412.391 to engage in the local distribution and sale of electric power and energy. Pursuant to Minnesota Statutes, section 412.361, the Shakopee Public Utilities Commission is authorized and empowered by law to regulate rates and charges for the distribution of electric energy within the City of Shakopee and to make arrangements for power and energy supply.

D. The Shakopee Public Utilities Commission (the "Commission") has determined that it will need a new source of power supply within the proximate future, did conduct an investigation and survey of available, alternative power suppliers and with the aid of outside experts determined to further examine and to enter into negotiations with the Agency.

E. The Commission has concluded a course of due diligence examinations upon the history, plans, financial position, generating and purchase power resources, material agreements and other relevant matters and has concluded that the Agency is likely to provide a reliable and reasonably priced supply of power and energy to meet the needs of the City of Shakopee. Therefore, the Commission has selected the Agency to provide its long term power supply needs commencing in 2006 and to apply now for membership in the Agency.

F. The Commission finds further assurance and support for its selection in that the Agency has provided a substantial amount of the City's power and energy requirements under contract with the Agency since 1995, that the governance of the Agency is in the hands of other Minnesota municipal electric utilities and that the City of Shakopee by its Commission will have the right and authority to actively participate in the management and direction of the Agency .

G. The Agency has provided to the Commission a copy of the Agency Agreement by and among the Members of the Agency and of the Agency Bylaws (each attached hereto) and the Commission has examined the Agency Agreement and the Bylaws to the extent deemed necessary and appropriate by the Commission. For all purposes of this Resolution, the Agency Agreement includes the Agency Agreement filed with the Minnesota Secretary of State on May 19, 1992 and amendments thereto as approved by Agency Representatives' Resolutions numbered 1993-1 (adopted March 3, 1993) and 2004-1 (adopted January 27, 2004). For all purposes of this Resolution the Agency Bylaws include the Bylaws of the Agency as originally adopted and as since amended by the Agency Directors and Representatives through the date of the adoption of this Resolution.

H. Pursuant to the Agency Statute, the concurrence of the City Council of the City of Shakopee is required as a precondition to the effectiveness of the Commission's adoption of the Agency Agreement as provided in this Resolution.

I. The Agency Statute and the Agency Agreement provide that cities which are members of municipal power agencies are not liable for the obligations of the municipal power agency.

Section 2. The participation of the City of Shakopee, Minnesota as a member in the Agency is hereby approved and authorized.

Section 3. The Commission agrees to the provisions of the Agency Agreement and the Bylaws of the Agency and the Chairman or any other officer of the Commission is hereby authorized and directed to execute the Agency Agreement for and on behalf of and as the deed of the City of Shakopee, Minnesota and the Secretary or any other officer of the Commission is herby authorized and directed to certify the adoption of this Resolution.

Section 4. In accordance with the Agency Act and the Agency Agreement, the following persons are hereby appointed as the initial representative and initial alternate representative of the City of Shakopee as a member of the Agency:

Representative:	Address:
Louis Van Hout	1030 E. 4th Ave. Shakopee MN 55379
Alternative Representative:	Address:
Joan Lynch	1030 E. 4th Ave. Shakopee MN 55379

The Representative or, in the absence of the Representative, the Alternative Representative, shall exercise all of the rights, duties and powers of the City of Shakopee as a member of the Agency for and on behalf of the City of Shakopee in accordance with the provisions of the Agency Statute, the Agency Agreement and the Bylaws of the Agency until a successor is appointed by the Commission.

Section 5. The Chairman of the Commission or any other officer of the Commission is authorized and directed to affix to the Agency Agreement a certified copy of this resolution for submission to the Secretary of State of Minnesota in accordance with the Agency Statute.

Section 6. The Chairman of the Commission or any other officer of the Commission is authorized and directed to deliver this Resolution to the City Council of the City of Shakopee and to request the concurrence of the City Council in this Resolution.

This Resolution is adopted by the Shakopee Public Utilities Commission on February 11, 2004.

Mark Miller
Commission President

Attest:

Jerry Fox
Commission Secretary

MINNESOTA MUNICIPAL POWER

AGENCY SALES AGREEMENT

This Agreement, entered into as of the _____ day of April, 2004, between the Minnesota Municipal Power Agency (Agency), a municipal power agency and political subdivision of the State of Minnesota, and the City of Shakopee by its Public Utilities Commission (City), a municipal corporation of the State of Minnesota and a member of the Agency.

W I T N E S S E T H:

WHEREAS, the Agency was organized under the Minnesota Municipal Electric Power Act to provide a means for those Minnesota cities which are members of the Agency to secure an adequate, economic and reliable supply of electric power and energy; and

WHEREAS, the Agency has the power to: (i) plan, acquire, construct, operate, maintain, and repair electric generation plant(s) and electric transmission systems or facilities for the production, transmission, purchase, sale, exchange or interchange of electric power and energy in or outside the State of Minnesota, and (ii) purchase, sell, exchange or transmit electric power and energy in and outside the State of Minnesota in such amounts as the Agency determines to be necessary and appropriate to meet its responsibilities to its members which includes entering into agreements with other parties for the purchase, sale, exchange or transmission of electric power and energy: and

WHEREAS, the City owns and operates a municipal electric system for the local distribution of electric energy and is authorized under the laws of the State of Minnesota to contract to buy from the Agency electric power and energy required for the City's present and future requirements; and

WHEREAS, in order to secure an adequate, economical and reliable supply of electric energy for the City's municipal electric system, the Agency and the City have determined that the Agency will sell to the City, and the City will purchase from the Agency, electric power and energy, transmission services, and dispatch services under the terms and conditions set forth in the agreement; and

WHEREAS, the Agency intends to acquire electric power and energy, transmission services, and dispatch services for sale to the City and to other members contracting with the Agency through the following means which include, without limitation, the purchase of these services from other utilities and the ownership of generation and transmission facilities; and

WHEREAS, in order to enable the Agency to enter into electric power and energy purchase contracts, transmission service contracts, and dispatch service contracts with suppliers of these services, it is necessary for the Agency to have binding contracts with the City and the other members of the Agency for the purchasing of electric power and energy from the Agency by the members;

NOW, THEREFORE, for and in consideration of the mutual covenants and terms contained in the Agreement, the following is agreed to by and between the parties to this Agreement:

SECTION 1. Sale and Purchase of Electricity

(a) The Agency agrees to sell and at the point(s) of delivery deliver to the City, and the City agrees to purchase and receive (Take or Pay) from the Agency, commencing January 1, 2006, and extending through the term of this Agreement, at the rates set forth under Section 3 of this Agreement, all electric power and energy which the City shall require to meet the needs of its customers over and above any electric power and energy the City is under contract, at the time the City signed this Agreement, to purchase from an electric power and energy supplier including (through December 31, 2005) the Agency and (through December 31, 2008) Northern States Power Company, or Xcel Energy or can generate from the City's own electric power generation which was operational at the time the City signed this Agreement. Schedule A attached to this Agreement lists the operational units.

(b) In the event that, pursuant to the Public Utility Regulatory Policies Act of 1978 or other provisions of law, electric power is required to be purchased from a small power production facility, a cogeneration facility or other facility, the City and the Agency shall use their best efforts to arrange for such purchases to be made by the Agency. If such arrangements cannot be made, then the City shall make the required purchases and sell the power purchased to the Agency. The City shall appoint the Agency to act as its agent in all dealings with the owner of such facility from which power is to be purchased and in connection with all other matters relating to such purchases.

SECTION 2. Service Characteristics, Point of Delivery, Ownership of Facilities

(a) Service Characteristics. Electric power and energy to be furnished under this Agreement shall be three-phase, 60 hertz, at 69 kv or higher voltage.

(b) Point of Delivery. A Point of Delivery shall mean that point at which the facilities of the City are connected to the transmission system which the Agency shall use to deliver electric power and energy to the City. Schedule B attached to this Agreement shows the facilities required for the connection between the Agency and the City, the location(s), the voltage(s), the Point(s) of Delivery, the point(s) of metering and the ownership of the facilities. This Schedule may be amended from time to time to reflect changes as agreed upon by the Agency and the City.

When electricity is measured at more than one Point of Metering, the total demand of the City's system shall be determined by combining the recorded demand at each Point of Metering during the same 15 minute interval.

(c) Ownership of Equipment. The Agency shall select, own, install and maintain all meters, telemeters, and associated equipment necessary, at each Point of Metering of the City, to measure and record the electric power and energy furnished to the City under this agreement. Such metering equipment shall provide a continuous record of the fifteen (15) minute integrated total demand of the City at such Point of Metering during each billing period throughout the term of this Agreement. Metering records shall be available at all reasonable times to authorized agents of the City.

The City shall provide and maintain, at its own expense, such facilities as are necessary to connect the City's system to the Point of Delivery, including any switching and protective equipment which the parties agree are necessary to protect the systems of the parties. The installation and maintenance of these facilities shall be performed by the City in accordance with specifications and procedures satisfactory to the parties.

(d) Meter Testing. The Agency shall test and calibrate meters or cause meters to be tested and calibrated by comparison with accurate standards at intervals of not less than twelve months. Any party shall have the right to have any metering device tested at any time at that party's expense; provided, however, that if any metering device is found to be inaccurate by more

than 1%, then the Agency will pay the cost of the test. Meters registering not more than one percent above or below normal shall be deemed to be accurate. The readings for any meter which shall have been disclosed by test to be inaccurate shall be corrected in accordance with the percentage of inaccuracy found by such test from the beginning of the first billing period after the most recent prior meter test but in no case for a period longer than 365 days. Should any meter fail to register, the electric power and energy delivered during such period of failure shall, for billing purposes, be estimated by the Agency and the City from the best information available. The Agency shall notify the City or cause the City to be notified in advance of the time of any meter reading or test so that the City's representative may be present at such meter reading or test.

SECTION 3. Rate

(a) The City shall pay the rates stated on Schedule C of this Agreement for all electric power and energy delivered by the Agency to the City. The customer, demand, and energy rates to be paid by the City for purchases of electric power and energy shall be as provided on Schedule C of this Agreement which may be changed by action of the Agency. The energy rates shall be adjusted through the Energy Adjustment Clause in Schedule C for the Agency's actual cost of energy.

(b) The rates charged to the City shall be nondiscriminatory compared with the rates charged to all other members of the Agency. City shall also pay the new member fee as provided in the New Member Agreement between City and Agency.

SECTION 4. Meter Readings and Payment of Bills

(a) The Agency shall read the meters at the end of each month for electric power and energy provided to the City since the last date the meter was read. The Agency shall send a statement to the City on or before the fifth calendar day after the meter is read stating the amount due from the City. If a meter cannot be read, the Agency shall estimate the amount of electric

power and energy delivered to the City during that billing period and send a statement to the City, with an adjustment for actual purchases in the next billing period.

The City shall pay for electric power and energy furnished under this agreement at the office of the Agency, or at the place and in the manner designated by the Agency, by the 20th day of the month in which the bill is mailed to the member; provided, however, that if said 20th day is a Saturday, Sunday or legal holiday in the State of Minnesota, the next following business day shall be the day on which such payment shall be due. In the event that the City fails to make payment by the 20th day of the month for the full amount due, the amount due shall be subject to an interest charge of one percent greater than the average of the daily prime rates published in the "Money Rates" section of the Wall Street Journal for each day from the date payment was due to the date the payment is received.

The Agency may, whenever any amount due remains unpaid after the due date, take all steps available to it under applicable law to collect such amount and, after giving 15 days advance notice in writing of its intention to do so, discontinue service under this agreement. The Agency may, whenever any amount due remains unpaid for 120 or more days after the due date and after giving 30 days advance notice in writing of its intention to do so, terminate this Agreement. The discontinuance of service or the termination of the Agreement shall not relieve the City from the liability for payment for electric power and energy furnished to the City prior to the discontinuance or termination of this Agreement.

(b) In the event the City desires to dispute all or any part of a bill, the City shall pay the full amount of the bill when due and notify the Agency in writing of the grounds on which any charges in the bill are disputed and the amount in dispute. The City will not be entitled to any adjustment on account of any disputed charges which are not brought to the attention of the Agency in the matter specified in this Agreement. Such adjustment shall be for the time period for which it can be established a billing error took place but in no event shall the adjustment period extend past the last meter test date or 365 days, whichever is shorter.

SECTION 5. Power Factor

The City shall have sufficient capacitors installed to maintain at least a 98 percent lagging hourly power factor during the City's peak load periods. The Agency and the City shall agree on the controlling of capacitor operation. It is the goal of both parties to maintain an hourly power factor of not less than 98 percent lagging during peak load periods and to avoid a leading hourly power factor during light load conditions.

In the event the City does not have sufficient capacitors installed, the City within 30 days after written notice from the Agency of such a deficiency, shall correct the deficiency or else provide the Agency with a written commitment to correct the deficiency. In the event the City makes a written commitment to add capacitors, the City shall exert its best efforts to expeditiously bring such equipment into service and to complete installation within one year from the initial notice or within such other time established by mutual agreement between the parties. If the additional capacitors are not installed within the allowed time and the Agency installs or has installed power factor control equipment, Agency shall bill the City a facilities fee based upon the Agency's cost of an equivalent amount of power factor control equipment.

SECTION 6. Continuity of Service

(a) In the event the Agency is prevented from delivering or the City is prevented from receiving electric power and energy as provided for in this Agreement by cause beyond its control including, but not limited to, acts of God, strikes, injunctions, breakdown, or the purpose of making repairs which by due diligence and foresight such party could not reasonably have been expected to avoid, neither party to this Agreement shall be liable to the other for its inability to perform. Both parties shall be prompt and diligent in removing and overcoming the cause of any interruption, but nothing in this Agreement shall be construed as permitting the Agency to

refuse to deliver, or the City to refuse to receive electric service after the cause of interruption has been removed.

(b) The Agency reserves the right to disconnect service in the event service to the City results in trouble on the Agency's system including, but not limited to: interruptions, grounds, radio or telephone interference, surges or objectionable voltage fluctuations, where such trouble is caused by the operation of the facilities of the City if, after giving notice in writing to the City of such trouble, the City fails to remedy the causes of the trouble within a reasonable time.

(c) The Agency does not guarantee that the supply of electric service under this Agreement will be free from interruption, and it is agreed that interruptions of the Agency's service, occasioned by any of the causes mentioned in this section, shall not constitute a breach of this Agreement on the part of the Agency, and the Agency shall not be liable to the City for damages resulting from such interruption of service. In the event of a service interruption, the parties shall act to restore service as soon as it can reasonably be accomplished. The Agency will at times exert itself toward the end of supplying as nearly constant service as is reasonably practicable. In case of impaired or defective service, the City shall immediately give notice to the Agency by telephone and confirm such notice in writing within ten working days.

(d) The Agency shall exercise due diligence to provide continuous uninterrupted electric power and energy to serve the full requirements of the City. If the Agency fails to do so, the City shall have the same right to terminate this Agreement and receive payment as set forth in Section 3; provided, however, that such termination may occur only after the City has given notice in writing to the Agency and the Agency fails to remedy the problem within a reasonable time.

SECTION 7. Term

This Agreement shall remain in effect through October 31, 2022 and if not then terminated by at least 5 years prior written notice given by either party to the other, shall continue in full force and effect until so terminated.

SECTION 8. General Terms and Conditions

(a) Maintenance of Retail Rates. The City agrees to maintain rates for electric power and energy to its consumers which provide to the City revenues sufficient to meet its obligations to the Agency under this Agreement and all other operating expenses of the City and all other obligations payable from such revenues. The City shall not be required to make payments to the Agency under this Agreement except from the revenues of the City's utility operations and from other funds of the City's utility operations.

(b) Assignment of Power Sales Agreement. This contract shall inure to the benefit of and shall be binding upon the respective successors and assigns of the parties to this Agreement. Except for the reason stated below, neither this Agreement nor any interest in this Agreement shall be transferred or assigned by either party to this Agreement except with the consent in writing of the other party, which consent shall not be unreasonably withheld. No assignment or transfer of this Agreement shall relieve the parties of any obligation under this Agreement.

If the Agency finds it necessary to issue Bonds for the financing of the Agency's operations or the construction, purchasing, or maintaining of facilities, the City agrees that the Agency may assign to any trustee or similar fiduciary designated in any Bond Resolution all of, or any interest in, its right, title, and interest in payments to be made to the Agency under the provisions of this Agreement as security for the payment of the principal, premiums, if any, and interest on any Bonds. Upon such assignment, the Agency may grant to such trustee any rights

and remedies in this Agreement provided to the Agency making the trustee a third party beneficiary of the covenants and agreements of the City contained in this Agreement.

(c) Information. The Agency and the City will promptly furnish to each other such information as may be reasonably requested from time to time in order to carry out more effectively the intent and purpose of this Agreement or as may be reasonably necessary and convenient in the conduct of the operations of the party requesting such information.

(d) Amendment. Except as provided for expressly in this agreement, neither this Agreement nor any terms hereof may be terminated, amended, supplemented, waived or modified except by an instrument in writing executed by each party to this Agreement.

(e) Notices. Any notices, demands, or requests required or authorized by the Agreement shall be deemed properly given if mailed postage prepaid:

on behalf of the Agency to:

Minnesota Municipal Power Agency
One City Hall Plaza
Chaska, Minnesota 55318

and on behalf of the City to:

Utilities Manager
Shakopee Public Utilities Commission
1030 East 4th Avenue
Shakopee, Minnesota 55379

The designation of the persons to be so notified or the address of such person may be changed at any time by similar notice.

(f) No Implied Waiver. The failure or delay of any party to enforce at any time any of the provisions of this Agreement, or to require at any time performance by a party of any provisions of this Agreement, shall neither be construed to be a waiver of such provisions nor affect the validity of this Agreement or the right of such party to thereafter enforce each and every provision of this Agreement.

(g) Severability. If any term or provision of this Agreement or the application of any term or provision of this Agreement shall to any extent be invalid or unenforceable, the remainder of this Agreement shall not be affected and each term and provision of this Agreement shall be valid and enforceable to the fullest extent permitted by law. The parties agree to negotiate a replacement provision or provisions in an effort to place the parties in the same or similar position reflected in the Agreement when originally signed.

(h) Applicable Law. This Agreement shall be governed by and construed in accordance with the laws of the State of Minnesota.

(i) Right of Access. Authorized representatives of the Agency and City shall be permitted to enter the other's premises at all reasonable times in order to carry out the provisions of the Agreement.

(j) Cooperation. If it becomes necessary by reason of any emergency or extraordinary condition for either the Agency or the City to request the other party to furnish personnel, materials, tools, or equipment for the accomplishment of its obligations under this agreement, the party so requested shall cooperate with the requesting party and render such assistance as the party so requested may determine to be available. The party making such request, upon receipt of properly itemized bills from the other party, shall promptly reimburse the other party for all costs properly and reasonably incurred by it in providing such assistance. The cost shall include an amount not to exceed ten percent (10%) for administrative and general expenses; such costs are to be determined on the basis of current charges or rates used in its own operations by the party rendering the assistance.

(k) No Resale. The City shall not sell at wholesale any of the electric power and energy delivered to the City under this Agreement to any customer of the City for resale by that customer, unless given prior written authorization by the Agency which will not be unreasonably withheld.

(l) Records and Accounts. The Agency and the City shall keep accurate records and accounts of its properties and operations. Such records shall be available to the other Party at all reasonable times.

(m) Reporting Requirements. The City shall provide from time to time whatever data, information, and estimates it may have regarding future energy requirements, which is reasonably requested by the Agency from the City and from Agency members. When the City becomes aware of a new load, and expansion of existing load, or plans to acquire service territory, that could reasonably be expected to have a peak load of 2 mW or greater, it shall promptly provide written notice to the Agency. Such notice shall include:

- Projected date of service,
- Projected monthly kW requirements,
- Projected monthly kWh requirements, and
- A general description of the load pattern.

Attested:

MINNESOTA MUNICIPAL POWER AGENCY

By: _____ 4/2/04
CHAIRMAN DATE

CITY OF SHAKOPEE, MINNESOTA
BY ITS PUBLIC UTILITIES COMMISSION

By: _____ 4/5/04
CHAIRMAN DATE

By: _____ 4/5/04
SECRETARY DATE

SCHEDULE A

OPERATIONAL GENERATING UNITS

Unit Name and / or Number	Unit Size (kW)
Pump House No. 3	150

SCHEDULE B

CONNECTION AND METERING FACILITIES
POINT(S) OF DELIVERY
between

Minnesota Municipal Power Agency
And
City of Shakopee

AMENDMENT TO

MINNESOTA MUNICIPAL POWER AGENCY
POWER SALES AGREEMENT

THIS AMENDMENT, entered into and made effective as of the 21st day of January, 2014, hereby amends the Agreement known as the Minnesota Municipal Power Agency Power Sales Agreement, as amended, by and between the Minnesota Municipal Power Agency ("Agency"), a municipal power agency and political subdivision of the State of Minnesota, and the CITY OF SHAKOPEE by its Public Utilities Commission, a municipal corporation of the State of Minnesota and a member of the Agency ("City"), dated April 27, 2004 (hereinafter referred to as the "Agreement").

WHEREAS, the Agency and the City wish to amend the term of the Agreement as set forth below:

NOW, THEREFORE, IT IS AGREED AS FOLLOWS:

(a) Section 7 of the Agreement, which currently provides as follows:

> **SECTION 7. Term**
>
> This Agreement shall remain in effect through October 31, 2040 and if not then terminated by at least 5 years prior written notice given by either party to the other, shall continue in full force and effect until so terminated.

shall be replaced in its entirety by the following paragraph:

> **SECTION 7. Term**
>
> This Agreement shall remain in effect through December 31, 2050, and if not then terminated by at least 5 years prior written notice given by either party to the other, shall continue in full force and effect until so terminated.

(b) Section 6(d) of the Agreement, which currently provides as follows:

The Agency shall exercise due diligence to provide continuous uninterrupted electric power and energy to serve the full requirements of the City. If the Agency fails to do so, the City shall have the same right to terminate this Agreement and receive payment as set forth in Section 3; provided, however, that such termination may occur only after the City has given notice in writing to the Agency and the Agency fails to remedy the problem within a reasonable time.

Shall be replaced in its entirety by the following paragraph:

The Agency shall exercise due diligence to provide continuous uninterrupted electric power and energy to serve the full requirements of the City. If the Agency fails to do so, the City shall have the right, in addition to any other legal remedies, to terminate this Agreement by giving at least ninety (90) days written notice. Upon such termination, the Agency shall pay to the City, if it is then a member of the Agency, the amount that the City would be entitled to if the MMPA was dissolved on the date of termination; provided, however, that such termination may occur only after the City has given notice in writing to the Agency and the Agency fails to remedy the problem within a reasonable time.

With the intention of causing this Amendment to the Agreement to become binding on the date first set forth above, the parties have hereby signed this Amendment to the Agreement as set forth below.

By signing below, each party represents that it has taken all steps necessary to authorize and approve the execution of this Amendment as set forth below.

MINNESOTA MUNICIPAL POWER AGENCY

Attest: Dan Boyce

By: Steve Schmidt

Its: Chair

CITY OF SHAKOPEE, MINNESOTA
By its Public Utilities Commission

Attest:

By:

Its: PRESIDENT 5-5-2014

PUBLIC DOCUMENT
TRADE SECRET DATA HAS BEEN EXCISED

APPLICATION FOR INTEGRATED RESOURCE PLAN APPROVAL 2019 - 2033

SUBMITTED TO THE MINNESOTA PUBLIC UTILITIES COMMISSION

July 30, 2018

Table of Contents

Section 1. Executive Summary

This section is intended to provide a brief overview of the Minnesota Municipal Power Agency's (MMPA) Integrated Resource Plan (IRP).

Electric Utility Industry in Transition

The electric utility industry is in a period of transition. The industry is experiencing a shift in the following areas:

- Decreasing cost of generation resources such as battery storage systems, solar, and wind;
- Advancements in hardware and software technologies; and
- Stagnant load growth;

This transitional environment creates uncertainty in planning. Section 9 discusses MMPA's Planning Approach.

Begin Serving Elk River Municipal Utilities in October 2018

Elk River Municipal Utilities (ERMU) became the twelfth member of MMPA in June 2013. ERMU serves 11,400 metered electric customers and has a peak demand of approximately 65 MW. MMPA's electrical power load is projected to increase by approximately 20 percent with the addition of ERMU. The Agency will begin providing wholesale power to ERMU on October 1, 2018, under a power sales agreement that runs through 2050.

MMPA Strives to Meet Its Conservation Goal

The Agency strives to meet its conservation goal for reducing electricity use of its members' customers. MMPA focuses on conservation strategies with the lowest cost per kWh of electricity saved. MMPA's conservation programs are discussed in Section 6 under Energy Conservation and Demand Side Management.

Energy and Demand Growth Projected to Be Lower Than Historical Levels

MMPA's energy and demand growth are projected to be lower than historical levels. The 2004-2017 historical compounded annual energy growth rate was 1.8%, whereas the projected annual energy growth rate for 2019-2033 is 0.8%. The 2004-2017 historical growth rate for non-coincident peak (NCP) demand was 1.4%, whereas the projected growth rate for 2019-2033 is 0.8%. The slower growth rates are attributed to projected population slowdowns and improved conservation efforts, among other factors.

The table below shows MMPA's projected annual growth for energy, NCP demand, and coincident peak (CP) demand with the Midcontinent Independent System Operator (MISO).

	2019-2033
Energy Growth	0.8%
NCP Growth	0.8%
CP Growth	0.8%

Sections 4 and 5 and Appendix A provide further details on the projections and projection methodology.

No Capacity Needed Until Planning Year 2030

The Agency does not need capacity until planning year 2030. Since capacity is not needed for the next eleven years, at the direction of the Department of Commerce staff, an evaluation of resource alternatives was not conducted for this IRP. However, MMPA will continue to evaluate the energy market to understand options to meet its future electric supply needs. Capacity requirements are discussed in Section 8. The short-range action plan is discussed in Section 10 and the long-range plan is presented in Section 11.

MMPA Is Positioned to Meet the RES

MMPA is positioned to meet the Renewable Energy Standard (RES). Since the last IRP the Agency has added the following renewable resources to its portfolio:

- 78 MW Black Oak Getty Wind Farm (2016),
- 7.1 MW AC utility-level solar facility, Buffalo Solar (2017)

In addition, MMPA signed a power purchase agreement (PPA) for 170 MW of wind that is anticipated to be commercially available in December 2019. Section 12 addresses meeting the RES as well as the rate impact of complying with the RES.

MMPA's Plan Is in The Public Interest

MMPA's IRP is in the public interest. The Agency's plan allows MMPA to maintain flexibility during this electric industry transition period, reducing risks to its customers while keeping rates as low as practicable. MMPA's plan also minimizes negative environmental impacts through its emphasis on conservation and renewable energy. Section 13 further describes how MMPA's plan is in the public interest.

Section 2. About MMPA

This section provides overview information about the Minnesota Municipal Power Agency.

MMPA Is a Municipal Power Agency

MMPA is a municipal power agency formed in 1992 under Chapter 453 of Minnesota Statutes. The Agency is a political subdivision of the state of Minnesota.

MMPA provides electricity to its municipal utility members and they in turn sell that electricity to residential and business customers in their community. MMPA began supplying power to its members in 1995.

MMPA is governed by a board of directors.

Has 12 Member Cities

MMPA is composed of the following twelve Minnesota communities:

- Anoka
- Arlington
- Brownton
- Buffalo
- Chaska
- East Grand Forks
- Elk River
- Le Sueur
- North St. Paul
- Olivia
- Shakopee
- Winthrop

MMPA's member municipal utilities have approximately 74,000 retail customers in Minnesota with a combined population of approximately 160,000.

MMPA Is Mission-Driven

MMPA's mission is to provide reliable, competitively-priced power to its members and to create value for both the Agency and its members. In addition, MMPA is committed to supporting the communities it serves and does so by offering an energy education program, developing local power generation in member communities, providing conservation and renewable energy programs to members' customers, and converting waste from its

	member communities into electricity at the Hometown BioEnergy facility.
MISO Market Participant	MMPA is a market participant with MISO, a Federal Energy Regulatory Commission (FERC) regulated regional transmission organization that provides grid management services and open access to transmission facilities for the midcontinent market. MMPA is a registered generation owner and load serving entity and is responsible for submitting demand bids and generation resource offers on behalf of its members. MMPA participates in MISO zone 1.
Projected to Sell 1,925,452 MWh in 2019	MMPA is projected to sell 1,925,452 MWh of energy in 2019. In 2017, MMPA sold 1,515,800 MWh of energy. The increase in energy sales is largely from the addition of Elk River as a member community. MMPA will begin serving Elk River in October 2018.
2019 Projected Peak Load of 440 MW	MMPA projects a peak load of 440 MW in 2019. MMPA's peak load during the summer of 2017 was 344 MW on July 17, 2017. This load includes adjustments for transmission system losses, the MISO planning reserve margin, Western Area Power Administration (WAPA) allocations, and CIP savings.
First Owned Plant Completed In 2007	Faribault Energy Park (FEP), the first power plant to be owned by the Agency, was completed in 2007. The plant was built in two phases. The 159 MW simple cycle phase became operational in April 2005. The combined cycle phase, which increased both the capacity and fuel efficiency of the plant, became operational in the summer of 2007. MMPA's ownership of FEP marked a transition from a resource portfolio based solely on contracts to one that also includes Agency-owned assets. FEP is described in more detail in Section 7.
First Owned Wind Farm Completed in 2011	Oak Glen Wind Farm (OGWF) is MMPA's first owned wind farm. It is 44 MW and located near Blooming Prairie, Minnesota. It was awarded a U.S. Department of Energy "2012 Public Power Wind Award" for leadership, innovation, project creativity, and benefits to customers. OGWF's innovative ownership and financial structure also qualified the wind project to receive a $25.4 million federal grant. OGWF is described in more detail in Section 7.

Became a MISO Transmission Owner in 2013

MMPA became a transmission owning member of MISO in 2013. The Agency is the transmission owner of facilities in Chaska and Anoka.

Committed to Renewable Energy

MPPA is committed to economic renewable energy generation. In 2025, MMPA anticipates that 53% of its wholesale sales will come from renewable resources. MMPA's renewable energy sources include wind, solar, and bioenergy.

Avant Energy Manages MMPA

Minnesota Municipal Power Agency is governed by a board of directors and Avant Energy provides management services to the Agency under long-term contracts. Avant's services to MMPA include:

- Day-to-day management of operations including electricity purchasing and selling;
- Overall long-term strategic planning and management; and
- Accounting and financing.

Section 3. Business Environment

This section discusses the business environment in which MMPA operates. MMPA's IRP recognizes electricity market uncertainties that influence planning decisions.

Energy Industry in Transition

The energy industry is going through a period of transition that includes:

- Decreasing cost of generation resources such as battery storage systems, solar, and wind generation that allow these generation technologies to better compete with traditional fossil fuel-fired generation;
- Advances in hardware technology such as smart meters, as well as software technology such as energy management systems, that utilize artificial intelligence allowing customer access to real-time energy consumption information and providing better decision-making tools for utilities and their customers;
- Evolution of customer preferences where more utility customers than ever before express increased interest in their utilities procuring energy from cleaner sources of energy; and
- Scaling back of federal environmental regulations on one hand and ramping up of corporate commitment to solving environmental issues on the other.

The aforementioned transition in the energy markets and the uncertainties of the future trajectory of delivering cost effective, reliable power with small or no environmental impact contribute to a challenging planning environment.

Low Natural Gas Prices

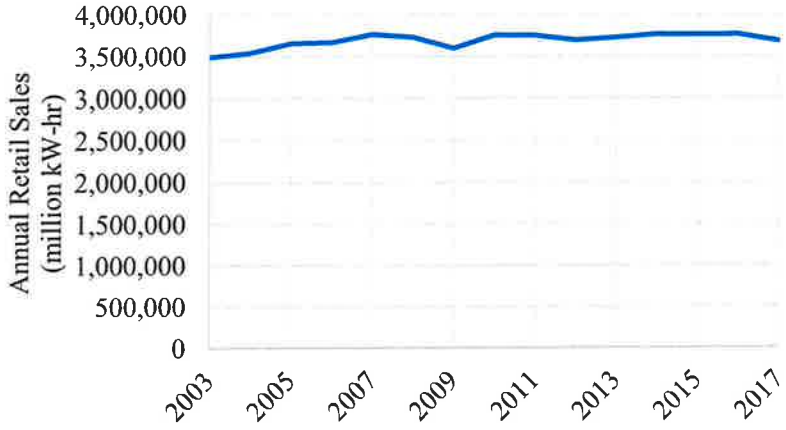
Natural gas prices are low. The shale revolution continues to put downward pressure on near to medium term gas prices. The U.S. became the largest producer of petroleum and natural gas in the world in 2012. The U.S. now produces nearly all the natural gas it consumes. Some studies project the share of shale in U.S. natural gas production is projected to rise to 45% by 2035.

Despite the robust near-term supply of natural gas, long term prices are less certain because of factors such as coal to gas switching, increased consumption from industrial and commercial production, possible environmental regulations, and increase in LNG and oil exports.

U.S. Retail Electric Sales Stagnant

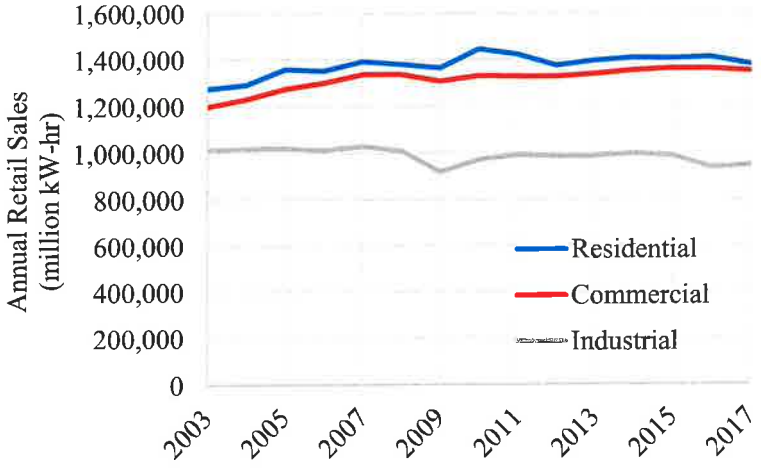
Stagnant growth of electric sales presents planning challenges for many utilities. Recent Energy Information Administration (EIA) data show that since 2003, overall retail electricity sales have risen by less than 5.5%. However, between 2007 and 2017, there was a decrease, albeit small, in overall retail electricity sales. EIA reported that between 2003 and 2017, slight residential and commercial user growth was offset by a decline in industrial users' sales. Below are two graphs that show this phenomenon.

Annual U.S. Retail Sales of Electricity



Source: U.S. Energy Information Administration

Annual U.S. Retail Sales of Electricity by Sector



Source: U.S. Energy Information Administration

EPA Emissions Standards Uncertain

Possible changes to U.S. Environmental Protection Agency (EPA) emissions standards increase planning uncertainties.

The EPA's Mercury and Air Toxics Standards (MATS) Final Rule, issued in April 2013, established emission limits for mercury, particulate matter, sulfur dioxide, acid gases, and certain individual metals for new power plants. The MATS Rule was expected to particularly affect the cost of future coal and oil-fired power plants if it fully went into effect. After reviews by courts, the D.C. circuit court suspended the case indefinitely.

In 2015, the EPA also reviewed the research linking smog exposure to adverse health effects such as asthma. Subsequently, the EPA updated the ozone rules with stricter limits to tighten standards on ozone from 75 parts per billion (ppb) to 70 ppb. In a court filing in April 2017, the federal government said the EPA officials appointed by the new administration were reviewing the 2015 rule to determine whether the EPA should reconsider some or all of the rule.

In addition, the federal government is reviewing the Clean Power Plan, which aims to cut emissions from existing power plants by 32% by 2030, and the Waters of the United States (WOTUS) rule. These emissions standards and rules could be scaled back or eliminated.

In March 2017, in a broad executive order on energy, the Interagency Working Group on the Social Cost of Greenhouse Gases was disbanded. This order withdrew the group's technical documents that form the scientific and economic basis for calculating the social cost of carbon and provide federal agencies a key tool to measure the benefits of cutting greenhouse gas emissions. While the absence of guidance from the federal government on the cost of carbon and other emissions could lead to confusion in certain types of planning scenarios, the Minnesota Public Utilities Commission has established emission costs. The costs are in its order *Updating Environmental Cost Values* issued on January 3, 2018 and in its order *Establishing 2018 and 2019 Estimate of Future Carbon Dioxide Regulation Costs* issued on June 11, 2018.

Initiatives to Decrease Carbon Emissions

While the federal government has indicated a desire to the scale back or eliminate environmental regulations, individual states and some cities are taking initiatives and setting goals and rules to first cap and then decrease carbon emissions from certain sectors of their economies. In Minnesota, the legislature has a state CO_2 reduction

goal of 30% by 2025 and 80% by 2050 (Minn. Stat. § 216H.02). Some of the largest cities in the U.S, including New York, Chicago, Atlanta and more than 30 others have also set ambitious emissions reductions goals.

Generation Interconnection Risks

In January 2017, the Federal Energy Regulatory Commission (FERC) conditionally approved Queue Reform 4.5 which revises the MISO generation interconnection process. Queue Reform 4.5 aims to improve the timeliness and efficiency of the interconnection process. MISO continues to incorporate Queue Reform 4.5 into the active interconnection study cycles and its Business Practices Manuals.

Timing and cost risks from the generation interconnection process persist during implementation of queue reform and may remain into the near future. MISO launches two cycles of new interconnection study groups each year for different regions. Many of the active interconnection study groups are seeing delays in the cycle process schedule. It is unknown when or if the queue reform will improve the timeliness of the interconnection process. This creates planning challenges for interconnection timing. A provisional interconnection alternative exists, but this option could create operational and transmission upgrade cost risks.

MISO Market Enhancements Continue

MISO is the entity that manages the reliable and cost-effective delivery of electricity and conducts transmission planning activities in 15 states, including Minnesota, and the Canadian province of Manitoba. MISO commenced its market operations for energy and financial transmission markets in 2005, followed by ancillary services markets in 2009, and capacity markets in 2010. Since its inception, MISO has continued to introduce or propose market enhancements and rule changes.

In 2011, MISO introduced the concept of a dispatchable intermittent resource (DIR) to address the uncertainties associated with the intermittency of wind resources. At that time, MISO had less than 10,000 MW of registered wind generation. MISO now hosts over 17,500 MW of registered wind. Over 12,500 MW of this wind is in Iowa, Minnesota, and North Dakota and MISO has managed the concentrated wind resources, locational prices, and reliability effectively.

MISO is now in the process of incorporating energy storage into its markets and complying with FERC orders 841 and 845. On April 3, 2017, MISO made a compliance filing with FERC where it revised Module A of its Tariff to add a new term called Stored Energy

Product Type 2 that would participate in energy, capacity, and ancillary service markets through the storage and discharge of electrical energy in response to set point instructions.

While the above market enhancements seem to address some of the immediate concerns of market participants, other enhancements have not had the desired effect. For instance, in 2013, MISO administered its first annual capacity auction. The system wide clearing price of $1.05 per megawatt-day for the 2013-2014 planning year reflected ample supply of generation and demand response resources in MISO and the robustness of the transmission system. The system-wide clearing price for the 2018-2019 planning year was $10.00 per megawatt-day for all zones except zone 1, which cleared at $1.00 per megawatt-day. Both clearing prices from the most recent MISO auction are low and suggest the abundance of capacity in the near term. However, the absence of long-term capacity markets and price signals for the cost of long-term capacity create planning challenges and discourage long-term investment.

The Independent Market Monitor (IMM) that monitors market activity in MISO reported in its *2016 State of the Market Report for the MISO Electricity Markets*:

> "Capacity market design issues described in this report have contributed to understated price signals, which will become an increasing concern as the capacity surplus falls due to retirements and units exporting capacity to PJM. "

Economic Uncertainty Necessitates Planning Flexibility

In the context of long-term planning, uncertainty exists because of high budget deficits, the unknown future of entitlement programs, the rising cost of living, the challenges addressing climate change, and deregulation. Increased economic uncertainty therefore necessitates the need for flexibility in energy supply planning.

Section 4. Projected Energy Requirements – 2019 to 2033

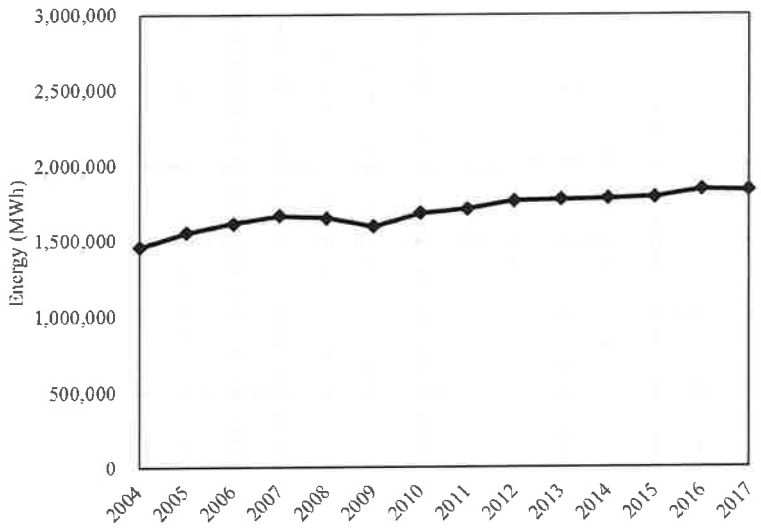
This section discusses MMPA's historical and future energy requirements.

Historical 1.8% Energy Growth Rate

Over the period 2004 to 2017, MMPA member energy requirements grew at a compound annual growth rate of approximately 1.8% for all twelve MMPA members.

The following graph shows historical MMPA member energy requirements for the years 2004 to 2017, the time period for which data is available for all twelve member cities. MMPA only served a portion of Shakopee's load until 2009. Therefore, the data has been adjusted to include all of Shakopee's load. MMPA has not historically served Elk River, but the data has been adjusted to include this load.

Minnesota Municipal Power Agency
Historical Member Energy Requirements (MWh)



MMPA Will Begin Serving Elk River in October 2018

MMPA will start providing electric service to Elk River in October 2018. The significant step up in projected energy in 2018 and 2019 is attributable to this load addition.

Linear Regression Model Used to Project Energy

A linear regression model was used to project energy usage for this IRP. The variables in the model are:

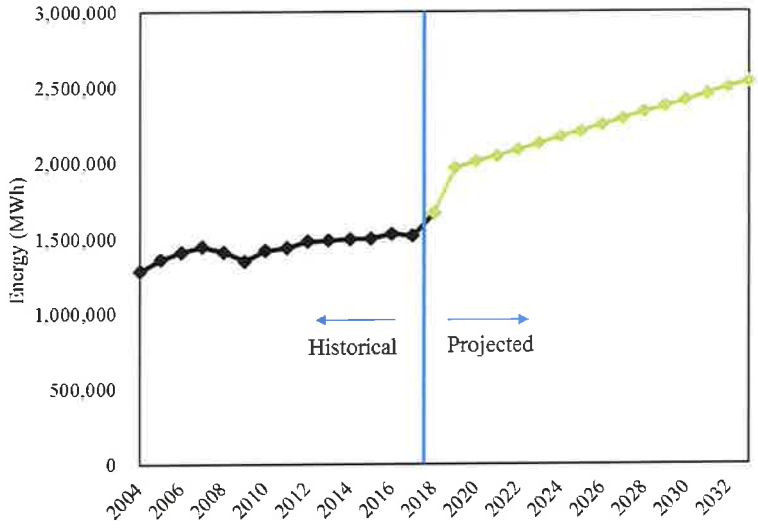
- Weather (heating degree days and cooling degree days)
- Population
- Income per capita

Details on the inputs and assumptions of the methodology can be found in Appendix A.

Projected 1.8% Energy Growth Rate without New Conservation

MMPA's projected energy growth rate without new conservation is 1.8% for the 2019-2033 projection period. The following graph shows historical and projected MMPA base energy requirements, without conservation adjustments, for the period 2004 to 2033.

Minnesota Municipal Power Agency
Historical & Projected Base Member
Energy Requirements (MWh) Without Conservation



New Conservation Assumed to Reduce Annual Energy Growth Rate By 1.0%

New conservation measures are assumed to reduce the Agency's annual energy growth rate by approximately 1.0%. For further clarification, the base case of 1.3% conservation does not translate into a 1.3% reduction in the energy growth rate because the requirements for CIP savings calculations are based upon a lagging 3-year average of MMPA's energy consumption. MMPA's current level of energy conservation is built into the historical energy usage data that is an input into the linear regression model. Section 6 discusses in detail MMPA's current and future conservation efforts.

Lower CIP Savings Would Increase Energy Requirements

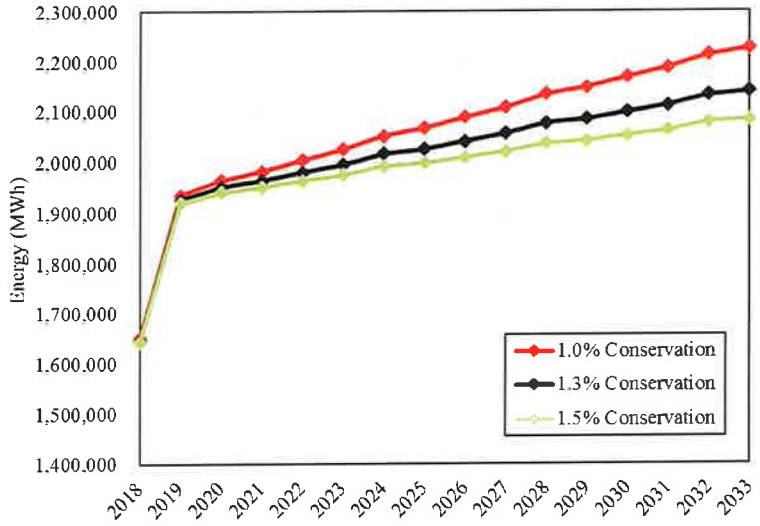
MMPA continues its successful conservation improvement program and strives to meet its CIP goals in the future. However, planning processes need to take into consideration the uncertainties associated with longer-term effectiveness of CIP programs and the possibility of diminishing returns.

This IRP contemplates three conservation rate cases for planning purposes:

- 1.0% Low Case
- 1.3% Base Case
- 1.5% High Case

Lower CIP savings in the future would increase energy requirements. The following chart shows MMPA's energy requirements for the three CIP savings cases:

Minnesota Municipal Power Agency
Projected Conservation-Adjusted Member Energy (MWh)



MMPA's CIP efforts and corresponding results are discussed in Section 6.

Lower Population Growth Rate Would Lower Electric Load Growth

Slower population growth correlates with slower load growth in the energy projections. Historical and projected population compounded annual growth rates (CAGR) for MMPA member cities are shown in the table below. Projections are based on Woods and Poole long term growth rates. Population growth rates are projected to be lower

than historical population growth rates for all MMPA members.

[TRADE SECRET DATA BEGINS

TRADE SECRET DATA ENDS]

Additional Members Would Increase Energy Requirements

MMPA's projected energy requirements would increase if the Agency were to take on additional members. This IRP assumes that the 12-member Agency does not take on any additional members during the projection period.

Large Retail Load Additions Would Increase Energy Requirements

MMPA's projected energy requirements would increase if its members were to take on new large retail loads. This IRP does not include any new large retail loads during the projection period.

Less Supply from WAPA Would Increase Energy Requirements

Two of MMPA's members currently receive allocations of energy (approximately 95,000 MWh per year) from the Western Area Power Administration (WAPA). Both members have long-term contracts for these energy allocations. However, WAPA could reduce the amount of energy and power available to its customers in the future. This would represent a policy change from the past. If WAPA decreases the energy available to its customers, MMPA's energy requirements would increase, because the Agency provides all of the energy to these two members that is not supplied by WAPA. This IRP assumes that WAPA allocations remain at the current contract amounts throughout the projection period.

More Electric Use for Transportation Could Increase Energy Requirements

In previous IRPs, we discussed electricity used as a fuel for transportation. This concept continues to hold the potential to reduce oil reliance and reduce carbon emissions from transportation. Increased market penetration of electric and hybrid vehicles in MMPA member communities could increase energy requirements.

A recent paper published by the California Energy Commission[1] analyzes the plug-in electric vehicle charging infrastructure needed to achieve California's goal of 1.5 million zero-emission vehicles (approximately 5% of vehicles) by 2025. The report estimates that in California, electric vehicles could add more than 1 GW of peak demand by 2025. Even though California has more than five times the number of vehicles on the road compared to Minnesota[2], the paper still demonstrates the significant increase in energy requirements that could occur once electric vehicles penetrate a market.

MMPA recognizes the potential increase in energy requirements over the long term from electric and hybrid vehicles. However, this IRP assumes no increase in MMPA's electric load from electric vehicles, since in Minnesota and MMPA communities, this technology currently has a low penetration and its future penetration is unknown.

MMPA Energy Projections

The table below shows MMPA's base energy projections as well as energy requirements with and without new conservation.

Year	Base Energy	Plus Olivia WAPA Adjustment	Plus East Grand Forks WAPA Adjustment	Energy Requirements without New Conservation	Plus 1.3% Conservation	Energy Requirements with New Conservation
2019	2,060,055	(22,307)	(73,051)	1,964,697	(39,245)	1,925,452
2020	2,105,762	(22,381)	(73,304)	2,010,077	(59,553)	1,950,524
2021	2,140,052	(22,307)	(73,051)	2,044,694	(81,606)	1,963,088
2022	2,180,669	(22,307)	(73,051)	2,085,311	(105,533)	1,979,777
2023	2,221,401	(22,307)	(73,051)	2,126,043	(130,836)	1,995,207
2024	2,268,293	(22,381)	(73,304)	2,172,608	(156,374)	2,016,234
2025	2,303,249	(22,307)	(73,051)	2,207,891	(182,106)	2,025,785
2026	2,344,346	(22,307)	(73,051)	2,248,988	(208,067)	2,040,921
2027	2,385,222	(22,307)	(73,051)	2,289,864	(234,229)	2,055,635
2028	2,432,844	(22,381)	(73,304)	2,337,159	(260,588)	2,076,571
2029	2,467,272	(22,307)	(73,051)	2,371,914	(287,118)	2,084,796
2030	2,508,287	(22,307)	(73,051)	2,412,929	(313,869)	2,099,060
2031	2,548,832	(22,307)	(73,051)	2,453,474	(340,809)	2,112,665
2032	2,596,684	(22,381)	(73,304)	2,500,999	(367,937)	2,133,062
2033	2,630,808	(22,307)	(73,051)	2,535,450	(395,222)	2,140,227
Growth Rate (2019-2033)				**1.8%**		**0.8%**

[1] California Energy Commission, *California Plug-In Electric Vehicle Infrastructure Projections 2017-2025*, March 2018, CEC-600-2018-001.
[2] U.S. Department of Transportation Federal Highway Administration, *State Motor Vehicle Registrations – 2016,* November 2017, https://www.fhwa.dot.gov/policyinformation/statistics/2016/mv1.cfm.

Section 5. Projected Demand Requirements – 2019 to 2033

This section discusses MMPA's historical and future demand requirements. This IRP examines both MMPA's Non-Coincident Peak (NCP) demand requirements and MMPA's Coincident Peak (CP) demand requirements with MISO. In accordance with Department of Commerce (DOC) instruction and in compliance with MISO, MMPA uses its CP demand requirements for planning purposes in this IRP.

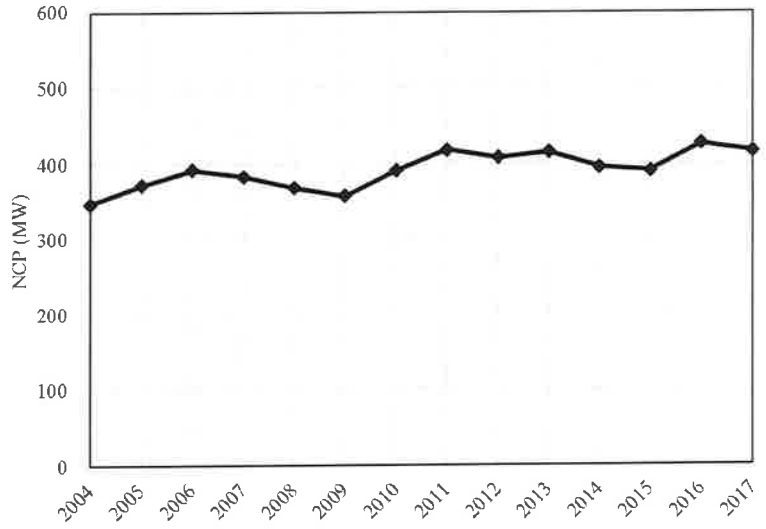
Historical 1.4% NCP Demand Growth Rate

Over the period 2004 to 2017, MMPA member NCP demand requirements grew at a compound annual growth rate of approximately 1.4% for all twelve MMPA members.

The following graph shows historical MMPA member NCP demand requirements for the years 2004 to 2017, the time period for which data is available for all twelve member cities. MMPA only served a portion of Shakopee's load until 2009. Therefore, the data has been adjusted to include all of Shakopee's load. MMPA has not historically served Elk River, but the data has been adjusted to include this load.

The demands recognize a 2.3% transmission loss factor, and an 8.4% planning reserve margin. Actual planning reserve requirements have varied from 2004-2017, but for consistency across historic years, this IRP assumes 8.4% for all periods.

Minnesota Municipal Power Agency
Historical Member NCP Demand (MW)



Weather Normalized Load Factor Approach Used to Project Demand

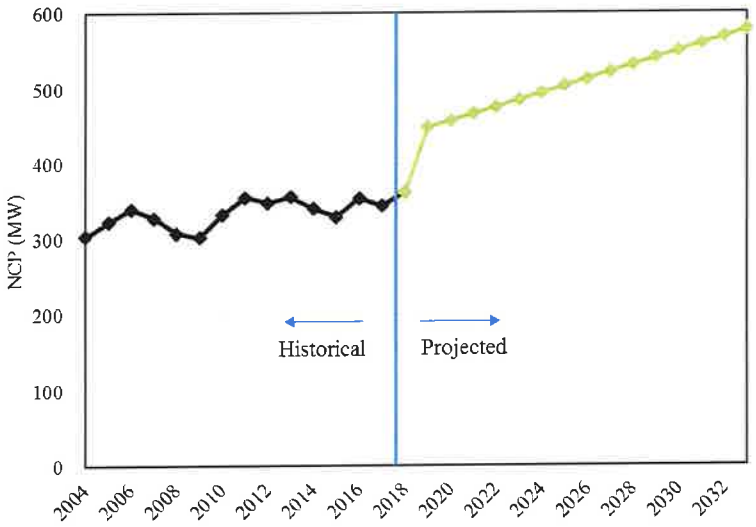
NCP demand for the Agency was projected using a weather normalized historical average load factor (approximately 56%) which was applied to MMPA's projected base energy requirements net of conservation.

Details on the inputs and assumptions of the methodology can be found in Appendix A.

Projected 1.8% NCP Demand Growth Rate without New Conservation

MMPA's projected NCP demand growth rate without new conservation is 1.8% for the 2019-2033 projection period. The following graph shows historical and projected MMPA NCP demand requirements for the years 2004 to 2033. The demands recognize a 2.3% transmission loss factor, and an 8.4% planning reserve margin.

Minnesota Municipal Power Agency
Historical & Projected Base Member NCP Demand (MW)
Without New Conservation



New Conservation Assumed to Reduce NCP Demand Growth Rate By 1.0%

New conservation measures are assumed to reduce the annual growth rate of MMPA's NCP requirements by 1.0%. The base case of 1.3% conservation does not translate into a 1.3% reduction in the demand growth rate because the requirements for CIP savings calculations are based upon a lagging 3-year average of MMPA's power consumption. Section 6 discusses in detail MMPA's current and future conservation efforts.

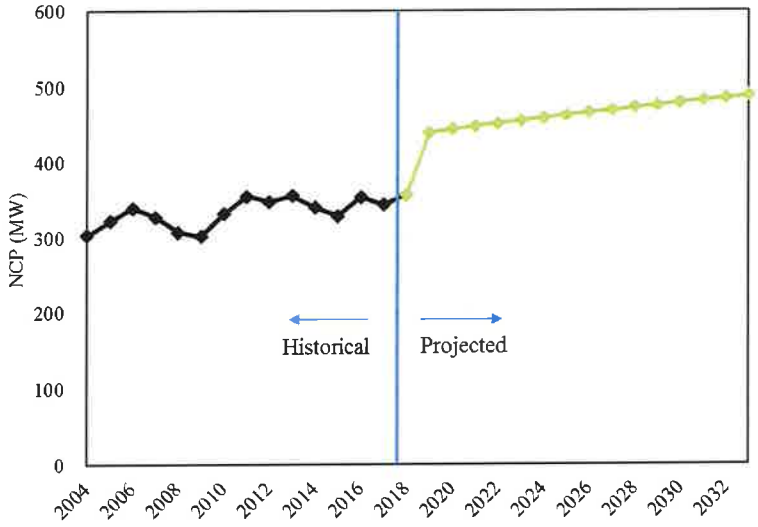
Projected 0.8% NCP Demand Growth Rate with New Conservation

MMPA's projected NCP demand growth rate including new conservation is 0.8% for the 2019-2033 projection period, shown in the table below.

	2019-2033
NCP Growth Rate Without New Conservation	1.8%
Effect of Conservation	1.0%
NCP Growth Rate With New Conservation	0.8%

The following graph shows historical and projected MMPA NCP demand requirements for the years 2004 to 2033. Both recognize a 2.3% transmission loss factor, and an 8.4% planning reserve margin.

Minnesota Municipal Power Agency
Historical & Projected Conservation-Adjusted
Member NCP Demand (MW)



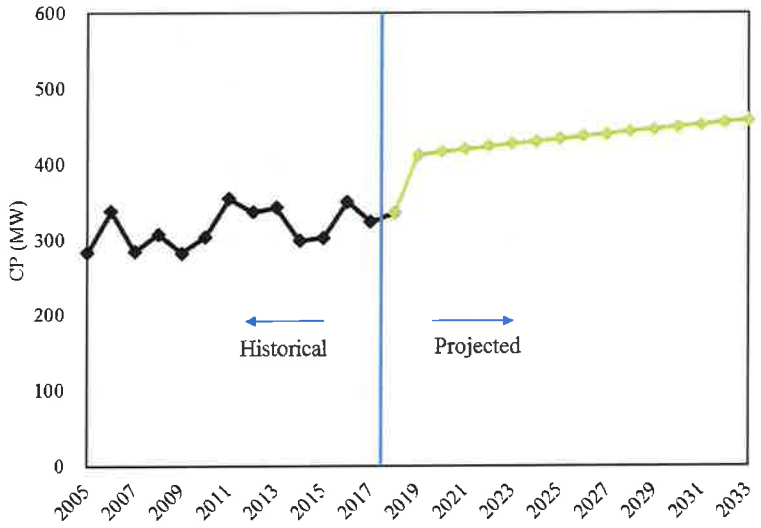
Coincidence Factor Approach Used to Project CP Demand

MMPA's demand at the time of MISO's peak (CP demand) was projected using a coincidence factor approach. An average historical coincidence factor (for summer months during the years 2005 to 2016, approximately 94%) was utilized to obtain MMPA's CP demand projection. Details on the methodology can be found in Appendix A.

Projected 0.8% CP Demand Growth Rate with New Conservation

MMPA's projected CP demand growth rate including new conservation is 0.8% for the 2019-2033 projection period. The following graph shows historical and projected MMPA CP demand requirements for the years 2005 to 2033. Because MISO's market opened in 2005, coincident peak data is not available in 2004. This data includes conservation adjustments, transmission losses of 2.3%, and a planning reserve margin of 8.4%.

Minnesota Municipal Power Agency
Historical & Projected Conservation-Adjusted Member CP Demand (MW)



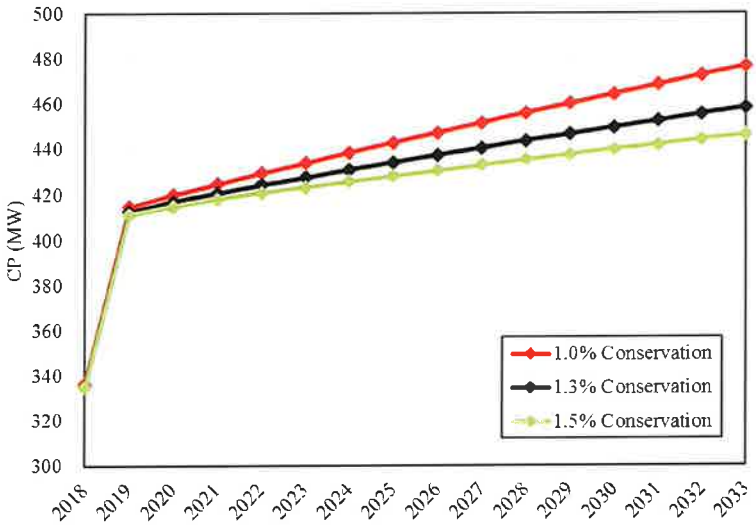
MMPA uses CP demand requirements for planning purposes in this IRP.

Lower Conservation Rates Would Increase Capacity Requirements

Lower conservation rates would increase capacity requirements. This IRP assumes a 1.3% energy conservation rate for planning purposes, however, high and low cases of 1.5% and 1.0% are also considered. See Section 6 for further details on conservation.

The graph below shows MMPA's CP demand projections based upon 1.0%, 1.3%, and 1.5% conservation levels. Both sets of projections recognize a 2.3% transmission loss factor, and an 8.4% planning reserve margin.

Minnesota Municipal Power Agency
Projected Conservation-Adjusted CP Demand (MW)



Lower Population Growth Rate Would Lower Electric Load Growth

Slower population growth correlates with slower load growth in demand projections. Demand is calculated using energy projections which are correlated to population growth. A comparison of historical and projected population compounded annual growth rates for MMPA member cities shows a deceleration in population growth across all MMPA members for the projection period. Please see Section 4 for details.

Additional Members Would Increase Demand Requirements

MMPA's projected demand requirements would increase if the Agency were to take on additional members. This IRP assumes that the 12-member Agency does not take on any additional members during the projection period.

Large Retail Load Additions Would Increase Demand Requirements

MMPA's projected demand requirements would increase if its members were to take on new large retail loads. This IRP does not include any new large retail loads during the projection period.

Less Supply from WAPA Would Increase Demand Requirements

Two of MMPA's members currently receive allocations of power (approximately 15.7 MW) from the WAPA. Both members have long-term contracts for these power allocations. However, WAPA could reduce the amount of energy and power available to its customers in the future. This would represent a policy change from the past. If WAPA decreases the power available to its customers, MMPA's demand requirements would increase, because the Agency

provides all of the demand to these two members that is not supplied by WAPA. This IRP assumes that WAPA allocations remain at the current contract amounts throughout the projection period.

The Effect of Electric Vehicles on Peak Demand is Unclear

In Section 4, it was discussed that MMPA's energy requirements would increase with an increase in electric vehicle use. However, the effect of electric vehicle use on demand is unclear.

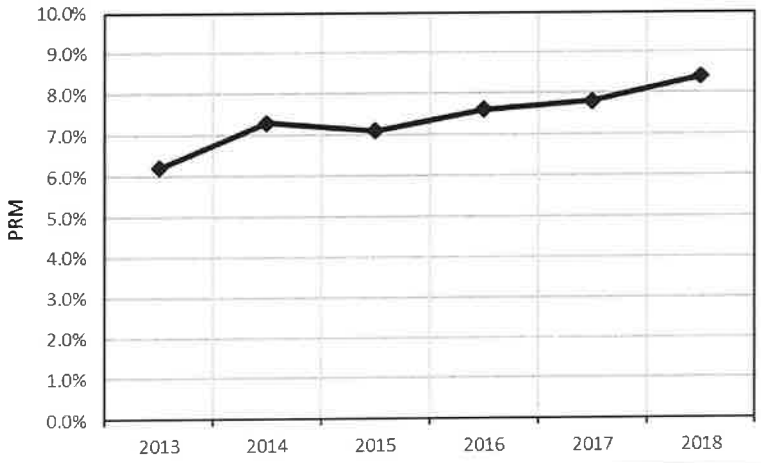
The California Energy Commission (CEC) report discussed in Section 4 estimated electric vehicles in California could add more than 1 GW of peak demand by 2025, assuming California reaches its goal of 1.5 million zero-emission vehicles (approximately 5% of all vehicles). The report described an electric vehicle charging profile consisting of a small at-home charging load ramp in the morning, work-place charging during the day, and a steep at-home charging load ramp in the early evening. This charging profile would likely increase peak demand. However, an alternative electric vehicle charging profile, where the majority of charging occurs during overnight off-peak hours, may have limited impact on peak demand.

This IRP assumes no increase in demand requirements during the projection period because the level of electric vehicle penetration and the effect of electric vehicles on peak demand is not clear.

Higher MISO Planning Reserve Margin (PRM) Would Increase Capacity Requirements

Historically, MISO's planning reserve margin (PRM) has varied by planning year as shown in the chart below. This IRP uses a PRM of 8.4%, consistent with the most recent planning year, to calculate MMPA's planning resource margin requirements (PRMR). Future increases in PRM would increase MMPA's capacity requirements.

MISO Planning Reserve Margin



Higher Transmission Losses Would Increase Capacity Needs

This IRP assumes a 2.3% transmission loss factor for the projection period. Historically, transmission losses have varied by MISO Zone, Local Balancing Area (LBA), and planning year.

MMPA's entire load is in MISO Zone 1. The Agency currently serves load in two LBAs within Zone 1. The vast majority of MMPA's load is in the NSP LBA, where transmission losses are 2.4%. The remainder of MMPA's load is in the OTP LBA, with transmission losses of 3.1%. In October 2018, MMPA will begin serving Elk River load in the GRE LBA, with transmission losses of 1.4%. For the purposes of this IRP, the Agency assumes aggregate 2.3% transmission losses.

Future increases in transmission losses would increase MMPA's capacity needs.

Higher Generation Forced Outage Rate Would Reduce Recognized Capacity

An increased generation forced outage rate, as measured by equivalent demand forced outage rate (EFORd), would decrease the capacity market credits MMPA would receive for its generation resources. EFORds for the planning horizon were based on the resource-specific EFORds for the 2018-19 planning year. If EFORds increase during the planning horizon, MMPA's capacity requirements would increase. Conversely, if EFORds decrease, MMPA's capacity requirements would decrease.

MMPA's Energy, NCP Demand, And CP Demand Projections

The table below summarizes MMPA's energy, NCP demand, and CP demand projections from 2019 to 2033. The energy projections have been adjusted for conservation and WAPA allocations. The NCP and CP projections have been adjusted for these same factors, as well as for transmission losses and the MISO PRM.

Minnesota Municipal Power Agency
Energy and Demand Projections

Year	Energy (MWh)	MMPA NCP (MW)	MMPA CP (MW)
2019	1,925,452	440.4	412.6
2020	1,950,524	444.9	416.9
2021	1,963,088	449.0	420.7
2022	1,979,777	452.7	424.2
2023	1,995,207	456.2	427.5
2024	2,016,234	459.8	430.8
2025	2,025,785	463.2	434.0
2026	2,040,921	466.6	437.2
2027	2,055,635	469.9	440.3
2028	2,076,571	473.4	443.6
2029	2,084,796	476.5	446.6
2030	2,099,060	479.8	449.6
2031	2,112,665	482.9	452.5
2032	2,133,062	486.2	455.6
2033	2,140,227	489.1	458.3

Section 6. Energy Conservation and Demand Side Management

This section discusses MMPA's energy conservation and demand side management efforts. The Agency's energy conservation programs delay the need for new generation and reduce energy consumption.

State Legislature Established a CIP Energy Savings Target

In 2007, the State Legislature revised the Conservation Improvement Program (CIP) statute to set an annual energy savings goal for each electric utility beginning in 2010.

Seven of the twelve MMPA member communities participate in the CIP program managed by the Agency. The other five member communities manage their own energy efficiency programs at the municipal utility level.

In 2017 State Legislature Exempted Small Utilities from CIP

In 2017, the State Legislature revised the CIP statue to exempt electric utilities with fewer than 1,000 customers from participating in the program. Two MMPA member communities qualify for this exemption, however, both utilities have opted to continue to participate.

MMPA Strives to Meet Its CIP Spending Requirement and Energy Savings Target

MMPA strives to meet its CIP spending requirement and energy savings target. MMPA has undertaken significant efforts to develop a CIP portfolio to meet its CIP energy savings target now and into the future.

Agency-Managed CIP Spending 2015-2017

MMPA has consistently met its annual CIP spending goal of 1.5%. The table below shows annual CIP dollars spent and the percentage of gross operating revenue (GOR) over the period 2015 through 2017.

CIP Spending – MMPA-Managed Portfolio

	2015	2016	2017
CIP Spending	$522,895	$537,421	$558,071
% of GOR	1.5%	1.5%	1.5%

Agency-Managed CIP kWh Savings 2015-2017

MMPA's annual CIP kWh savings are slightly below the State's savings goal of 1.5%. The table below shows annual kWh saved over the period 2015 through 2017.

CIP Energy Savings – MMPA-Managed Portfolio

	2015	2016	2017
kWh Savings	3,767,808	4,889,312	4,547,594
% of Sales	1.1%	1.4%	1.3%

Agency-Managed CIP Program Cost $0.12/kWh of Energy Saved

Based upon data for 2017, MMPA's CIP program cost an average of $0.12/kWh of electricity saved. MMPA's Agency-managed CIP portfolio aims to incorporate programs that help to maintain an average rebate cost-to-electricity savings ratio of $0.10/kWh or less.

This IRP Assumes 1.3% Energy Savings for Projections

This IRP assumes a CIP savings rate of 1.3%, although a low case of 1.0% and a high case of 1.5% were also analyzed. The Agency strives for a 1.5% savings rate, however, planning processes need to take into consideration the uncertainties associated with longer term effectiveness of CIP programs and the possibility of diminishing returns.

Lighting Rebates Are a Cost-Effective Use of CIP Funds

In 2017, 54% of MMPA's Agency-managed CIP rebate spending went toward lighting projects. Lighting rebates are a cost-effective means of achieving energy savings. The table below highlights the return on investment in MMPA's 2017 CIP cycle.

Lighting Program Effectiveness – MMPA-Managed Portfolio

Program	kWh saved	Cost/kWh saved
Commercial Lighting – New	349,850	$0.10
Commercial Lighting - Retrofit	2,719,646	$0.07
Residential LED	16,834	$0.23
Lighting Giveaway	137,975	$0.21
LED Street Lighting	191,685	$0.15
All Lighting Combined	3,415,990	$0.09

Rebates with High Energy Savings Potential

The appliance recycling bonus rebate, the variable frequency drive rebate, and custom rebates all have high energy savings potential. The appliance recycling bonus rebate ($0.05/kWh electricity saved) creates customer incentives to unplug inefficient refrigerators and freezers and the variable frequency drive rebate ($0.05/kWh electricity saved) incentivizes improving heating, ventilation, and air conditioning (HVAC) system operation.

Custom rebates are unique in that they give MMPA flexibility to support its members' customers on projects with high energy savings potential. Custom commercial and industrial projects also achieve a

good return on investment, averaging $0.07 spent per kWh of electricity saved in 2017. Custom rebates made up 7% of MMPA's Agency-managed CIP rebate spending in 2017.

A Variety of Programs Offered to Residential, Commercial, and Industrial Customers

Programs offered in the Agency-managed 2018 CIP Portfolio include:

Residential:

- ENERGY STAR Appliance Rebate (Clothes Washer, Dishwasher, Refrigerator, Freezer, Dehumidifier)
- Secondary Refrigerator or Freezer Recycling Rebate
- LED Lighting Rebate
- Quality Installed Central Air Conditioning (AC) and Air Source Heat Pump Rebate
- AC Tune Up Rebate
- Custom Rebates

Commercial and Industrial:

- Lighting Retrofit Rebate
- Lighting New Construction Rebate
- Variable Frequency Drives (VFD) Rebates
- Vending Machine Controller Rebate
- Custom Rebates

Members Pursue Direct Low-Income CIP Projects

In 2017, the Agency-managed CIP members spent an estimated $45,570 on low-income energy conservation projects.

Low-income spending is measured at the city level and each member city must meet its own individual spending requirement. MMPA continues to pursue low-income programs that provide direct benefits to low-income customers such as purchasing energy efficient lighting and appliances for section 8 housing and offering free light bulbs to low-income customers.

CIP Energy Savings Goals Will Become More Challenging to Achieve in the Future

It is anticipated that CIP energy savings goals will become more challenging to achieve in the future. Lighting rebates and custom rebates for equipment such as HVAC equipment are some of the most successful programs. These installations have long useful lives, therefore, in the future, there will be fewer available projects for updates. Additionally, energy-saving technological advancements are likely to slow down in areas such as lighting.

Despite this, MMPA still believes it will have a continuing energy savings impact during the 2019-2033 projection period by focusing on

	developing CIP strategies with the lowest cost per kWh of electricity saved, focusing on new energy-efficient technologies, and communicating with customers.
Industrial and Commercial Programs Are Important to Program Success	Participation by industrial and commercial customers is critical for achieving energy savings goals. Industrial and commercial customers are larger energy users and therefore have greater energy savings potential. MMPA works to create relevant, cost-effective programs for these users.
MMPA Regularly Reevaluates Its CIP Offerings	MMPA continues to evaluate its program offerings and consider new programs. MMPA aims to direct its CIP spending to the most cost-effective programs. Since the 2013 IRP filing, MMPA added residential rebates for freezers and dehumidifiers, recycling of secondary freezers, and commercial rebates for a variety of new LED lamps and fixtures.
MMPA Continues to Reevaluate Demand Side Management Programs	MMPA currently has no demand side management programs, but continues to reevaluate potential options. The Agency had a load curtailment program and retired it when it became a less competitive option to acquire capacity as market prices for capacity became less expensive.

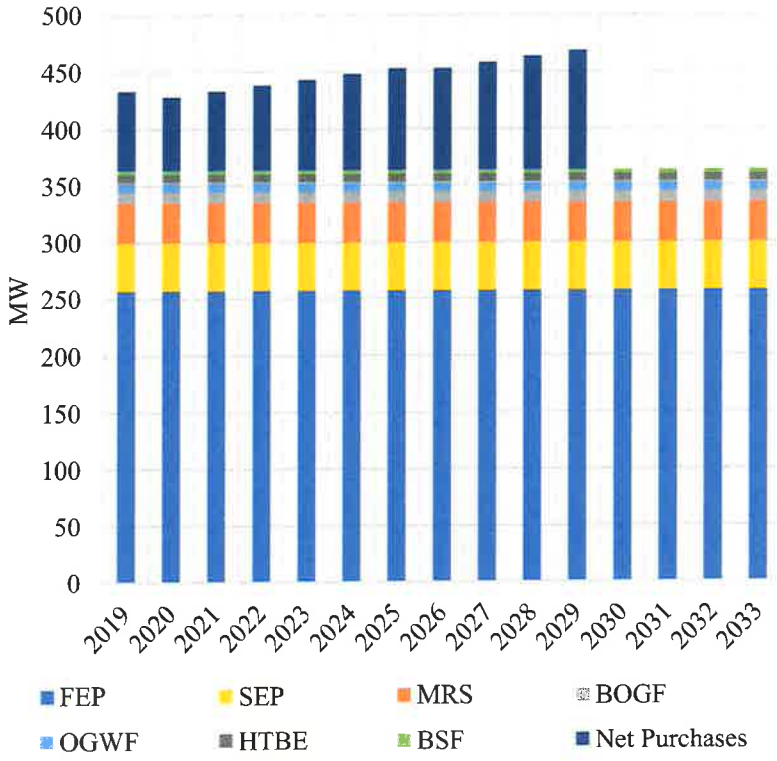
Section 7. Existing Resources

MMPA's existing resource portfolio is a mix of owned generation and power purchase agreements and a combination of renewable and conventional resources.

434 MW of Projected Power Supply Resources in 2019

MMPA projects that its power supply portfolio will consist of 434 MW of both contractual resources and Agency-owned generation for planning year 2019. The graph below shows MMPA's existing resources for the period 2019 to 2033.

Minnesota Municipal Power Agency
Power Supply Resources – Summer Capacity in MW
2019 to 2033



Key:

FEP: Faribault Energy Park
HTBE: Hometown BioEnergy
MRS: Minnesota River Station
BOGF: Black Oak Getty Wind Farm
Net Purchases: Bilateral Purchases
OGWF: Oak Glen Wind Farm
BSF: Buffalo Solar Facility
SEP: Shakopee Energy Park

MISO Capacity Measured by Unforced Capacity (UCAP)

MISO capacity is measured by Unforced Capacity (UCAP). UCAP is calculated by multiplying the Installed Capacity (ICAP) of a generating resource by 1 minus the Effective Forced Outage Rate (EFORd). Once the UCAP of a resource is calculated, market participants can convert UCAP to Zonal Resource Credits (ZRCs) to get capacity.

FEP Projected UCAP: 257.3 MW

Faribault Energy Park (FEP) is the first power supply resource financed and built by MMPA. The plant was built in two phases, with simple cycle operation beginning in April 2005. The combined cycle phase began operations in the summer of 2007, improving the fuel efficiency and increasing the maximum accredited summer output of the plant to 261 MW. The plant uses natural gas as its primary fuel.

FEP is an innovative power plant that uses a series of created wetlands for water management at the plant. Rainwater is collected and filtered before being used for steam production and equipment cooling. The wetlands area is open to the public as a park with several small trails.

The plant is also designed to be a "working classroom," with an observation room where visitors can view both the steam turbine and the plant's control room.

FEP's ICAP for PY 2018 is 261.3 MW. The EFORd used to calculate FEP's 2018 UCAP is 1.53%. This IRP assumes that FEP's EFORd will continue to be 1.53% for the 15-year planning horizon of 2019-2033.

FEP		
	2018	**2019-2033**
ICAP	261.3	261.3
EFORd	1.53%	1.53%
UCAP/ZRC	257.3	257.3

SEP Projected UCAP: 42.6 MW

Shakopee Energy Park (SEP) is a 46.4 MW distributed energy resource. Located in Shakopee near Canterbury Park, SEP uses fuel-efficient reciprocating engines to generate local, reliable power for the City of Shakopee as well as contributing to the overall power supply for all MMPA member communities.

SEP's ICAP for PY 2018 is 46.4 MW. The EFORd used to calculate SEP's 2018 UCAP is 8.19%. This IRP assumes that SEP's EFORd will continue to be 8.19% for the 15-year planning horizon of 2019-2033.

SEP

	2018	2019-2033
ICAP	46.4	46.4
EFORd	8.19%	8.19%
UCAP/ZRC	42.6	42.6

MRS Projected UCAP: 35.6 MW

The Minnesota River Station (MRS) plant is a peaking resource. The City of Chaska, one of the Agency's members, owns the plant and sells the entire output to MMPA under a long-term contract. MRS became operational in the summer of 2001 and is accredited for approximately 40 MW in the summer. Minnesota River Station uses natural gas as its primary fuel.

MRS's ICAP for PY 2018 is 39.6 MW. The EFORd used to calculate MRS' 2018 UCAP is 10.00%. This IRP assumes that MRS's EFORd will continue to be 10.00% for the 15-year planning horizon of 2019-2033.

MRS

	2018	2019-2033
ICAP	39.6	39.6
EFORd	10.00%	10.00%
UCAP/ZRC	35.6	35.6

BOGF Projected UCAP: 9.7 MW

At the end of 2016, the Minnesota Municipal Power Agency (MMPA) expanded its portfolio of renewable resources to include power from the 78-megawatt (MW) Black Oak Getty Wind Farm (BOGF) located in Stearns County, Minnesota.

MMPA signed a long-term contract with Sempra U.S. Gas & Power for the output of the Black Oak Getty Wind Farm. The wind farm, composed of 39 wind turbines, entered commercial operation in December 2016. The term of the contract is 30 years.

BOGF ICAP for PY 2018 is 78 MW. For wind resources, MISO uses capacity credit instead of EFORd. The UCAP is simply calculated by multiplying the ICAP by the capacity credit. The capacity credit used to calculate BOGF's 2018 UCAP is 12.44%. This IRP assumes that BOGF will continue to receive the 2018 capacity credit for the 15-year planning horizon.

BOGF

	2018	2019-2033
ICAP	78	78
Capacity Credit	12.44%	12.44%
UCAP/ZRC	9.7	9.7

HTBE Projected UCAP: 7.2 MW

Hometown BioEnergy (HTBE) is an 8 MW biomass facility, located in the MMPA member community of Le Sueur. It provides dispatchable, on-peak renewable energy to the Agency.

Hometown BioEnergy supports the local community by collecting and processing local wastes to create a renewable source of electricity that flows directly into the Le Sueur power system.

The facility was recognized by POWER Magazine as a 2014 Top Renewable Plant.

HTBE ICAP for PY 2019 is projected to be 8 MW. The EFORd used to calculate HTBE's 2019 UCAP is 10.42%, which is the class average for diesel generation in MISO in 2018. This IRP assumes that HTBE's EFORd will match the 2018 class average for diesel generation for the IRP period through 2033.

HTBE

	2019-2033
ICAP	8
EFORd	10.42%
UCAP/ZRC	7.2

OGWF Projected UCAP: 7.6 MW

The 44 MW Oak Glen Wind Farm (OGWF) is MMPA's first owned wind farm and is located near Blooming Prairie, Minnesota.

The U.S. Department of Energy awarded OGWF with the "2012 Public Power Wind Award" for leadership, innovation, project creativity, and benefits to customers. OGWF's innovative ownership and financial structure qualified the wind project to receive a $25.4 million federal grant.

OGWF ICAP for PY 2018 is 44 MW. For wind resources, MISO uses capacity credit instead of EFORd. The UCAP is simply calculated by multiplying the ICAP by the capacity credit. The capacity credit used to calculate OGWF's 2018 UCAP is 17.35%. This IRP assumes that OGWF will continue to receive the 2018 capacity credit for the 15-year planning horizon.

OGWF

	2018	**2019-2033**
ICAP	44	44
Capacity Credit	17.35%	17.35%
UCAP/ZRC	7.6	7.6

Buffalo Solar Projected UCAP: 3.6 MW

The Buffalo Solar Facility (BSF), a 7.1 MW AC utility-scale solar facility located in the Agency's member community of Buffalo, entered commercial operation at the end of 2017. MMPA signed a 22.5-year, long-term contract with HQC Tatanka Wi Solar Power Generation LLC, for the output of the solar facility.

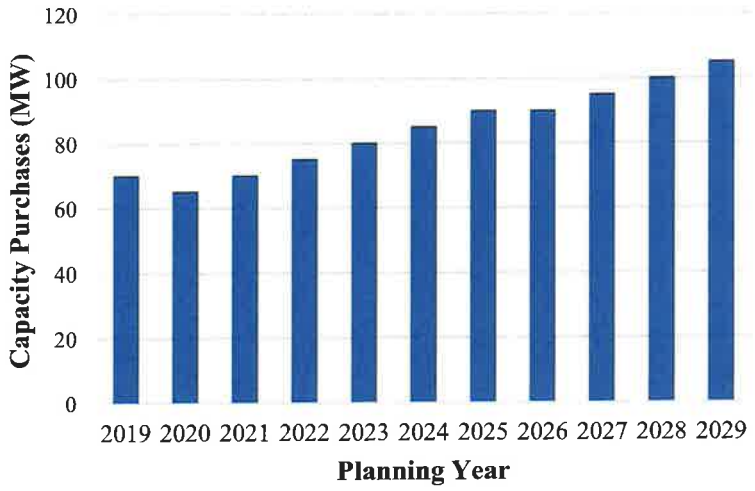
BSF

	2018	2019-2033
ICAP	7.1	7.1
Capacity Credit	50.00%	50.00%
UCAP/ZRC	3.6	3.6

MMPA Purchased Capacity for PY 2019-2029

MMPA has purchased between 65 and 105 MW of MISO Zonal Resource Credits (ZRCs) for 2019 through 2029.

Minnesota Municipal Power Agency
Capacity Purchases (ZRCs)
2019-2029

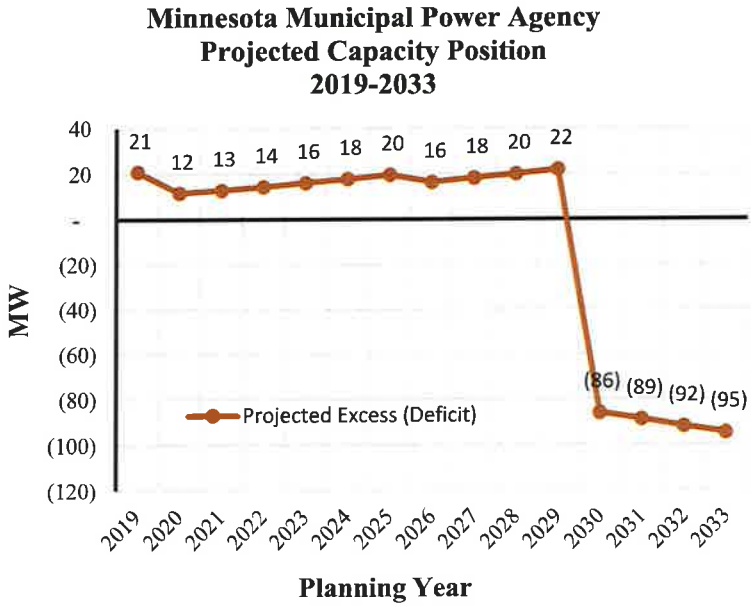


Section 8. Additional Capacity Requirements

This section describes MMPA's projected additional capacity requirements over this IRP's planning period.

No Capacity Needed Until 2030

MMPA projects that it will not need new capacity until planning year 2030. The chart below shows MMPA's projected capacity position by year during the projection period.



Projected Capacity Need Grows From 86 MW in 2030 To 95 MW in 2033

MMPA projects that its first year of capacity need is PY 2030 for 86 MW. The expiration of a capacity contract and member load growth are the main reasons for the capacity need.

Planning Reserve Margin Requirement of 8.4% Is Assumed

MMPA currently participates in the MISO PRM pool. This IRP assumes a PRM of 8.4% for the projection period, as discussed in previous sections.

Transmission Losses Assumed to Be 2.3%

Transmission losses of 2.3% are assumed for this IRP, as discussed in previous sections.

Section 9. Planning Approach

This section outlines MMPA's planning approach.

No Capacity Needed Until PY 2030

As discussed in Section 8, MMPA projects no capacity need until planning year 2030.

Maintain Flexibility in Time of Technological Transition

MMPA seeks to maintain flexibility in its power supply plan during a time of technological change. The rapid changes occurring with renewable and storage technologies make flexibility vital to any planning process. Securing additional capacity in the market allows MMPA to later reevaluate the changing market and capture opportunities that do not currently exist.

Continue to Reevaluate Feasibility of Resource Alternatives

MMPA will continue to reevaluate resource alternatives to determine what option is the most effective to meet future requirements. Included in these alternatives is the option to buy capacity. MMPA maintains long term relationships with many MISO market participants and looks for opportunities to buy capacity when cost effective.

Committed to Renewable Energy

The Agency is committed to renewable energy. MMPA plans to meet or exceed Minnesota's Renewable Energy Standard (RES). Section 12 further discusses MMPA's plan to meet renewable requirements.

Section 10. Short-Range Plan

This section outlines MMPA's short-range action plan.

Projected Capacity Needs Met Through Planning Year 2029

MMPA is not projected to need capacity until planning year 2030.

MMPA Signed 170 MW Wind PPA

MMPA has signed a wind PPA for 170 MW of energy. The resource is anticipated to begin commercial operation at the end of 2019. This PPA will help MMPA to meet the Renewable Energy Standard that is discussed in Section 12 and to meet its incremental energy needs with renewable energy.

Cover Capacity Needs in the Short-Term Market

As discussed in Section 8, MMPA is projected to have adequate capacity through planning year 2029. However, in the future if MMPA instead has a deficit, the incremental difference could be covered in the short-term capacity market.

Continue to Develop and Market Cost-Effective Conservation Programs

MMPA will continue to develop and market cost-effective conservation programs for its member utilities to offer to their retail customers. The Agency's philosophy is to focus on programs that generate the most energy savings per dollar spent. MMPA also remains committed to providing energy efficiency programs that benefit Minnesota's low-income households.

Section 11. Long-Range Plan

This section describes MMPA's long-range plan.

Capacity Not Needed Until Planning Year 2030

MMPA is not projected to need capacity until planning year 2030. The costs of different technologies for capacity are expected to change by the time the capacity is needed. For this reason, discussions with the Department of Commerce staff concluded that a detailed evaluation of resource alternatives is not needed for this IRP.

Monitor Cost of Generation Technologies

During this time, MMPA will continue to monitor the cost of generation technologies. In addition, MMPA will track Federal and State regulations, consumer preferences, and advances in technology.

Evaluate Resource Alternatives

When MMPA's capacity need becomes near term, the Agency would conduct a detailed evaluation of resource alternatives. The Agency anticipates considering new generation and power purchases to meet its needs. For new generation, a variety of technologies would be considered such as simple cycle gas, combined cycle gas, reciprocating engines, battery storage, solar, and wind.

Consider Capital, Operating, Fuel, and Externality Costs

In its evaluation of resources, MMPA would consider capital, operating, fuel, and externality costs of all resources. Externality costs would include environmental and regulatory costs of emissions as determined by the PUC.

Section 12. RES Compliance and Rate Impact

This section describes MMPA's efforts toward meeting the State of Minnesota's Renewable Energy Standard (RES) and the estimated rate impact of complying with the RES.

RES Requirement Projected to Grow to 511,000 MWh

MMPA's annual RES requirements are projected to grow from approximately 312,000 in 2019 to 511,000 in 2033. This is mainly because of ERMU's addition as the twelfth member to MMPA as well as the increasing RES requirements. The RES requirements are based on total retail electric sales. The calculations account for a 4.49% system loss between wholesale and retail sales. The table below summarizes the RES obligation for MMPA for the period 2019-2033.

Minnesota Municipal Power Agency
Projected RES Requirements

Year	Projected Wholesale Load (MWh)	RECs for RES Obligations
2019	1,925,452	312,617
2020	1,950,524	372,574
2021	1,963,088	374,974
2022	1,979,777	378,162
2023	1,995,207	381,109
2024	2,016,234	385,125
2025	2,025,785	483,687
2026	2,040,921	487,301
2027	2,055,635	490,814
2028	2,076,571	495,813
2029	2,084,796	497,777
2030	2,099,060	501,183
2031	2,112,665	504,431
2032	2,133,062	509,301
2033	2,140,227	511,012

RECs for Clean Energy Programs

In addition to its RES obligation, MMPA has retired RECs for its green pricing program and Clean Energy Choice Programs. While RECs retired for these programs are not significant (approximately 6,000 RECs for 2017), participation in these programs is increasing and would increase the total RECs needed.

Notwithstanding the foregoing, MMPA's current and future resources are projected to satisfy all of its future REC obligations.

970,000 RECs in Inventory

The Agency currently has over 970,000 RECs in its inventory. MMPA actively follows the REC markets and seeks opportunities to buy RECs to satisfy its future requirements. Below is the breakdown of MMPA's current REC inventory:

2014 Vintage RECs	119,648
2015 Vintage RECs	176,349
2016 Vintage RECs	169,724
2017 Vintage RECs	398,221
2018 Vintage RECs	109,559
Total	973,501

Five Existing Renewable Resources Projected to Generate 466,000 MWh/Year

MMPA's five existing resources are projected to generate approximately 466,000 MWh per year.

The table below shows the projected annual generation from these existing renewable resources:

Resource	Annual Generation (MWh)
Black Oak Wind Farm	307,000
Oak Glen Wind Farm	132,000
Buffalo Solar	14,000
Hometown BioEnergy	12,000
Hometown Wind	800
Total	465,800

Signed PPA Projected to Generate 600,000 MWh/Year

MMPA has signed a 30-year wind power purchase agreement with NextEra for 170 MW of generating capacity from the Dodge County Wind Farm. The facility has not yet been constructed, but has a contract commercial operation deadline of December 2019. The wind farm is projected to generate approximately 600,000 MWh of renewable energy per year.

MMPA Projects Meeting All of Its Incremental Energy Needs with Renewables

In 2033, MMPA's energy requirements of 2,140,227 MWh will be 214,776 MWh over its projected 2019 requirements. MMPA's renewable energy requirement for 2033 of 511,012 MWh is 238% of its incremental energy needs. By satisfying the RES, MMPA will meet all of its incremental energy needs through renewables. The effects of MMPA's conservation efforts are included in the base calculations.

MMPA Is Positioned to Meet the RES

MMPA is positioned to continue to meet the RES through its mix of purchases and resources.

Rate Impact of Complying with RES

MMPA's 2005 to 2017 RES rate impact ranged between 0.00 cents per kWh and 0.96 cents per kWh.

MMPA's projected RES rate impact for 2019-2033 ranges between 0.64 cents per kWh and (0.53) cents per kWh.

Details of these projections are included in Appendix C.

Dodge County Project Necessary to Meet RES Rate Impact Projections

The Dodge County project is necessary to meet the RES rate impact projections. MMPA's competitively priced PPA with Dodge County Wind Farm reduces the rate impact beginning with 2020. This project is projected to provide benefits between 0.09 cents per kWh and 0.55 cents to kWh.

Greenhouse Gas Emission Reduction Goals Were Achieved in 2015 and Are Projected to Be Achieved in 2025

MMPA's generation assets and power purchase agreements that contribute to meeting the RES also support meeting Minnesota's greenhouse gas emission reduction goals that are established in Minn. Stat. § 216H.02. Minnesota established a goal to reduce statewide greenhouse gas emissions across all sectors at least 15% below 2005 levels in 2015 and at least 30% below 2005 levels in 2025. The following table summarizes MMPA's greenhouse gas reductions for 2015 and 2025.

Minnesota Municipal Power Agency
Greenhouse Gas Reductions from 2005 Levels

	2015	2025
Total Emissions (lbs CO_2)	34%	63%
Emission Rate (lbs CO_2/MWh)	42%	76%

Section 13. MMPA's Plan Is in The Public Interest

This section discusses how MMPA's Integrated Resource Plan is in the public interest.

MMPA's Plan Provides Flexibility

MMPA's IRP gives the Agency flexibility to accommodate future uncertainties such as technological changes, penetration of electric vehicles, and energy policy. The Agency created this flexibility by purchasing capacity through planning year 2029. As 2029 approaches, MMPA will reevaluate load and costs to determine the best options for meeting its future capacity and renewable energy requirements.

MMPA's Plan Limits Environmental Effects

The Agency's plan limits negative environmental effects. MMPA projects that 53% of its wholesale sales will be from renewable resources in 2025. MMPA also continues to pursue increased energy conservation.

MMPA's Plan Meets the Public Interest Criteria in Rule 7843

MMPA's plan meets the public interest criteria set out in Commission Rule 7843.0500 Subp. 3, which are:

- Maintain or improve the adequacy and reliability of utility service
- Keep the customers' bills and the utility's rates as low as practicable, given regulatory and other constraints
- Minimize adverse socioeconomic effects and adverse effects upon the environment
- Enhance the utility's ability to respond to changes in the financial, social, and technological factors affecting its operations
- Limit the risk of adverse effects on the utility and its customers from financial, social, and technological factors that the utility cannot control

MMPA's plan includes a diverse set of resources to serve its load. The Agency's portfolio has both owned and contracted renewable and conventional resources. MMPA seeks to maintain flexibility in its power supply plan during a time of technological change. The rapid changes occurring with renewable and storage technologies make flexibility vital to any planning process. Securing additional capacity in the market allows MMPA to later reevaluate the changing market and capture opportunities that do not currently exist. This plan enhances the Agency's ability to respond to change during this transitional period for the energy industry. It also limits

the risk of adverse effects. By including renewable resources in its portfolio and promoting energy conservation, the Agency balances socioeconomic and environmental considerations.

Appendix A. Load Projection Methodology

This appendix describes the methodology used to project MMPA's energy and demand requirements for this Integrated Resource Plan.

Members' Energy Usage Was Projected with A Linear Regression Model

MMPA member energy usage was projected using linear regression analysis. The energy usage for three of MMPA's member cities (East Grand Forks, Buffalo, and Elk River) was projected separately from that of the other nine members. Those four projections were then combined to obtain the entire Agency's projected energy. The MMPA9 projection includes the member cities of Anoka, Arlington, Brownton, Chaska, Le Sueur, North St. Paul, Olivia, Shakopee and Winthrop. The historical monthly energy data sets for these four projections are as follows:

- **MMPA9**: Monthly energy usage from 1996–2017
- **East Grand Forks**: Monthly energy usage from 1996–2017
- **Buffalo**: Monthly energy usage from 2000–2017
- **Elk River**: Monthly energy usage from 2004–2017

Data constraints for East Grand Forks and Buffalo prompted the separate projections for those cities. Elk River was projected separately because MMPA begins serving its load in October 2018. Total MMPA energy requirements were projected by adding the results of these four regression models.

Throughout this appendix, all 12 MMPA member cities are referred to as MMPA12 and all 11 MMPA member cities, excluding Elk River, are referred to as MMPA11.

Explanatory Variables for Energy Projections Were Weather, Income, And Population

The explanatory variables used for the regression models were weather, income, and population.

Weather

Cooling degree days (CDD) and heating degree days (HDD) were both used as explanatory variables. All CDD and HDD data is supplied by the National Oceanic and Atmospheric Administration (NOAA). Historical CDD and HDD data for all member communities, except East Grand Forks, comes from the Minneapolis-St. Paul International Airport weather station. Historical CDD and HDD data for the East Grand Forks model comes from the Fargo weather station (the closest available). CDD and HDD projections are historical "normal" data from 1981-2010 (the latest "normal" data set available published by NOAA).

Income per Capita

Both historical and projected income data come from Woods and Poole Economics' *Minnesota State Profile 2017 State and County Projections to 2050*. This data is provided at the county level. The MMPA9 model uses a weighted average income variable, created by weighting each of those nine member cities' income per capita by the city's annual energy usage.

Population

Historical population data from 1988 to 2016 comes from the Minnesota State Demographic Center and the Metropolitan Council *Historic Household and Population Estimates*. Data was unavailable for the year 1989, so linear smoothing of 1988 and 1990 data was used. Population projections from 2019 to 2033 are based on actual data for 2016, annually increased by long term county population growth rates calculated from Woods and Poole projections.

All explanatory variables listed above were used in the MMPA9 model. For the East Grand Forks model, CDD and population were excluded because of low t-stat results. Minimal air conditioning load and a devastating 1997 flood likely explain the low t-stats for CDD and population, respectively.

Each model used monthly data to forecast monthly energy, which was then aggregated to provide annual energy projections.

Annual Energy Was Reduced by Conservation

Annual energy projections were decreased by 1.3% of the Agency's three-year rolling average retail energy usage. This reduction represents MMPA's assumption regarding new conservation measures.

Conservation levels of 1.0% and 1.5% were also analyzed, but the 1.3% base case was used for the purposes of this IRP. Conservation reductions lowered the compounded annual growth rate by 1.0%, resulting in a net annual growth rate of 0.8% for the base case energy usage.

Agency Energy Requirements Were Reduced By WAPA-Supplied Energy

Following adjustments for conservation, projected energy requirements were reduced by the energy that WAPA supplies to two MMPA member cities (Olivia and East Grand Forks). These WAPA allocations were assumed to remain at current levels throughout the projection period.

NCP Demand Was Projected Using a Weather Normalized Load Factor

MMPA's Non-Coincident Peak (NCP) demand requirements were projected by applying a weather normalized load factor to the Agency's energy projections. This weather normalized load factor of 55.9% was calculated as the average of annual weather normalized load factors from 2011 to 2017. The average load factor was then applied to the conservation-adjusted energy projections to obtain MMPA's projected NCP demand.

Demand at MISO's Annual Coincident Peak Was Projected Using A Coincidence Factor Approach

MMPA's demand at the time of MISO's peak (CP demand) was projected by applying a coincidence factor to the Agency's NCP projections. This coincidence factor of 93.9% was calculated as the average of monthly summer (June-September) coincidence factors from June 2005 to September 2016. The average coincidence factor was then applied to the NCP demand projections to obtain MMPA's projected CP demand.

CP Demand Was Adjusted for WAPA-Supplied Capacity

Like the energy projections, CP demand projections were reduced by the capacity that WAPA supplies to two MMPA member cities. These WAPA allocations were assumed to remain at the current contract levels throughout the projection period.

Capacity Requirements Include Losses and Reserves

The Agency's total capacity requirements are calculated by adding transmission system losses (2.3%) and planning reserve margin requirements (8.4%) to the projected CP demand requirements.

MMPA's entire load is in MISO Zone 1 and currently serves load in two Local Balancing Authorities (LBAs). The vast majority of MMPA's load is in the NSP LBA, where transmission losses are 2.4%. The remainder of MMPA's load is in the OTP LBA, with transmission losses of 3.1%. In October 2018, MMPA will begin serving Elk River load in the GRE LBA, which currently has transmission losses of 1.4%. For the purposes of this IRP, the Agency assumes aggregate 2.3% transmission losses.

MISO's planning reserve margin requirement is expected to be 8.4% in planning year 2018. For long term planning purposes, a planning reserve margin of 8.4% was used.

Appendix B. Advance Forecast

This appendix contains MMPA's filing to the Department of Commerce as outlined in Minnesota Administrative Rules Chapter 7610.

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION

INSTRUCTIONS

The individual worksheets in this spreadsheet file correspond closely to the tables in the paper forms received by the utility.
The instructions provided with the paper forms also pertain to the data to be entered in each of the worksheets in this file.
PLEASE DO NOT CHANGE THE **NAME** OR **ORDER** OF ANY OF THE WORKSHEET TABS IN THIS FILE

In general, the following scheme is used on each worksheet:

Cells shown with a light green background correspond to headings for columns, rows or individual fields.
Cells shown with a light yellow background require data to be entered by the utility.
Cells shown with a light brown background generally correspond to fields that are calculated from the data entered, or correspond to fields that are informational and not to be modified by the utility.

Each worksheet contains a section labeled Comments below the main data entry area.
You may enter any comments in that section that may be needed to explain or clarify the data being entered on the worksheet.

Please complete the required worksheets and save the completed spreadsheet file to your local computer.
Then attach the completed spreadsheet file to an e-mail message and send it to the following e-mail address:

rule7610.reports@state.mn.us

If you have any questions please contact:

Anne Sell
MN Department of Commerce
rule7610.reports@state.mn.us
(651) 539-1851

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION

7610.0120 REGISTRATION

ENTITY ID#	266
REPORT YEAR	2017

RILS ID#	U13724

UTILITY DETAILS	
UTILITY NAME	Minnesota Municipal Power Agency
STREET ADDRESS	220 South Sixth Street Suite 1300
CITY	Minneapolis
STATE	Minnesota
ZIP CODE	55402
TELEPHONE	(612) 349-6868
	Scroll down to see allowable UTILITY TYPES
* UTILITY TYPE	

CONTACT INFORMATION	
CONTACT NAME	Oncu Er
CONTACT TITLE	Sr. Vice President
CONTACT STREET ADDRESS	220 South Sixth Street Suite 1300
CITY	Minneapolis
STATE	Minnesota
ZIP CODE	55402
TELEPHONE	(612) 349-6868
CONTACT E-MAIL	Oncu.Er@AvantEnergy.com

COMMENTS

PREPARER INFORMATION	
PERSON PREPARING FORMS	Samuel Meersman
PREPARER'S TITLE	Sr. Manager
DATE	7/18/2018

ALLOWABLE UTILITY TYPES

Code

Private
Public
Co-op

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

7610.0310 Item A. SYSTEM FORECAST OF ANNUAL ELECTRIC CONSUMPTION BY ULTIMATE CONSUMERS

Provide actual data for your entire system for the past year, your estimate for the present year and all future forecast years.

Please remember that the number of customers should reflect the number of customers at year's end, not the number of meters.

			FARM	NON-FARM RESIDENTIAL	COMMERCIAL	MINING *	INDUSTRIAL	STREET & HIGHWAY LIGHTING	OTHER	SYSTEM TOTALS	Calculated System Totals
Past Year	2017	No. of Cust.									0
		MWH									0
Present Year	2018	No. of Cust.									0
		MWH									0
1st Forecast Year	2019	No. of Cust.									0
		MWH									0
2nd Forecast Year	2020	No. of Cust.									0
		MWH									0
3rd Forecast Year	2021	No. of Cust.									0
		MWH									0
4th Forecast Year	2022	No. of Cust.									0
		MWH									0
5th Forecast Year	2023	No. of Cust.									0
		MWH									0
6th Forecast Year	2024	No. of Cust.									0
		MWH									0
7th Forecast Year	2025	No. of Cust.									0
		MWH									0
8th Forecast Year	2026	No. of Cust.									0
		MWH									0
9th Forecast Year	2027	No. of Cust.									0
		MWH									0
10th Forecast Year	2028	No. of Cust.									0
		MWH									0
11th Forecast Year	2029	No. of Cust.									0
		MWH									0
12th Forecast Year	2030	No. of Cust.									0
		MWH									0
13th Forecast Year	2031	No. of Cust.									0
		MWH									0
14th Forecast Year	2032	No. of Cust.									0
		MWH									0

* MINING needs to be reported as a separate category only if annual sales are greater than 1,000 GWH. Otherwise, include MINING in the INDUSTRIAL category.

COMMENTS

MMPA is requesting an exemption from this forecast page, as it sells all of its electricity to its member municipal utilities at wholesale. The Agency does not project customer count by class as part of its future energy and demand forecasts. As discussed in the Integrated Resource Plan, MMPA uses projected population of member cities to project energy and demand requirements.

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

7610.0310 Item A. MINNESOTA-ONLY FORECAST OF ANNUAL ELECTRIC CONSUMPTION BY ULTIMATE CONSUMERS

Provide actual data for your Minnesota service area only, for the past year, your best estimate for the present year and all future forecast years.

Please remember that the number of customers should reflect the number of customers at year's end. not the number of meters.

			FARM	NON-FARM RESIDENTIAL	COMMERCIAL	MINING *	INDUSTRIAL	STREET & HIGHWAY LIGHTING	OTHER	MN-ONLY TOTALS	Calculated MN-Only Totals
Past Year	2017	No. of Cust.									0
		MWH									0
Present Year	2018	No. of Cust.									0
		MWH									0
1st Forecast Year	2019	No. of Cust.									0
		MWH									0
2nd Forecast Year	2020	No. of Cust.									0
		MWH									0
3rd Forecast Year	2021	No. of Cust.									0
		MWH									0
4th Forecast Year	2022	No. of Cust.									0
		MWH									0
5th Forecast Year	2023	No. of Cust.									0
		MWH									0
6th Forecast Year	2024	No. of Cust.									0
		MWH									0
7th Forecast Year	2025	No. of Cust.									0
		MWH									0
8th Forecast Year	2026	No. of Cust.									0
		MWH									0
9th Forecast Year	2027	No. of Cust.									0
		MWH									0
10th Forecast Year	2028	No. of Cust.									0
		MWH									0
11th Forecast Year	2029	No. of Cust.									0
		MWH									0
12th Forecast Year	2030	No. of Cust.									0
		MWH									0
13th Forecast Year	2031	No. of Cust.									0
		MWH									0
14th Forecast Year	2032	No. of Cust.									0
		MWH									0

* MINING needs to be reported as a separate category only if annual sales are greater than 1,000 GWH. Otherwise, include MINING in the INDUSTRIAL category.

COMMENTS

MMPA is requesting an exemption from this forecast page, as it sells all of its electricity to its member municipal utilities at wholesale. The Agency does not project customer count by class as part of its future energy and demand forecasts. As discussed in the Integrated Resource Plan, MMPA uses projected population of member cities to project energy and demand requirements.

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

7610.0310 Item B. FORECAST OF ANNUAL SYSTEM CONSUMPTION AND GENERATION DATA (Express in MWH)

NOTE: (Column 1 + Column 2) = (Column 3 + Column 5) - (Column 4 + Column 6)
It is recognized that there may be circumstances in which the data entered by the utility is more appropriate or accurate than the value in the corresponding automatically-calculated cell. If the value in the automatically-calculated cell does not match the value that your utility entered, please provide an explanation in the Comments area at the bottom of the worksheet.

		Column 1	Column 2	Column 3	Column 4	Column 5	Column 6	Column 7	Column 8	CALCULATED
		CONSUMPTION BY ULTIMATE CONSUMERS IN MINNESOTA in MWH [7610.0310 B(1)]	CONSUMPTION BY ULTIMATE CONSUMERS OUTSIDE OF MINNESOTA in MWH [7610.0310 B(2)]	RECEIVED FROM OTHER UTILITIES in MWH [7610.0310 B(3)]	DELIVERED FOR RESALE in MWH [7610.0310 B(4)]	TOTAL ANNUAL NET GENERATION in MWH [7610.0310 B(5)]	TRANSMISSION LINE SUBSTATION AND DISTRIBUTION LOSSES in MWH [7610.0310 B(6)]	TOTAL WINTER CONSUMPTION in MWH [7610.0310 B(7)]	TOTAL SUMMER CONSUMPTION in MWH [7610.0310 B(7)]	(GENERATION + RECEIVED) MINUS (RESALE + LOSSES) MINUS (CONSUMPTION) SHOULD EQUAL ZERO
Past Year	2017			1,515,800	2,614,667	1,098,867				0
Present Year	2018			1,645,737	2,662,829	1,017,092				0
1st Forecast Year	2019			1,925,452	2,942,544	1,017,092				0
2nd Forecast Year	2020			1,950,524	3,568,245	1,617,721				0
3rd Forecast Year	2021			1,963,088	3,579,364	1,616,276				0
4th Forecast Year	2022			1,979,777	3,596,053	1,616,276				0
5th Forecast Year	2023			1,995,207	3,611,483	1,616,276				0
6th Forecast Year	2024			2,016,234	3,633,954	1,617,721				0
7th Forecast Year	2025			2,025,785	3,642,061	1,616,276				0
8th Forecast Year	2026			2,040,921	3,657,197	1,616,276				0
9th Forecast Year	2027			2,055,635	3,671,911	1,616,276				0
10th Forecast Year	2028			2,076,571	3,694,292	1,617,721				0
11th Forecast Year	2029			2,084,796	3,701,072	1,616,276				0
12th Forecast Year	2030			2,099,060	3,714,751	1,615,691				0
13th Forecast Year	2031			2,112,665	3,728,161	1,615,496				0
14th Forecast Year	2032			2,133,062	3,750,003	1,616,941				0

COMMENTS

Under the Midwest Independent Transmission System Operator's (MISO) energy market, utilities purchase all of their load from MISO and sell all of the output from their generating resources to MISO. This table has been completed reflecting that structure of the industry. MMPA supplies its memeber cities with energy for resale. The energy values reported here correspond to a calendar year reporting period.

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

7610.0310 Item C. PEAK DEMAND BY ULTIMATE CONSUMERS AT THE TIME OF ANNUAL SYSTEM PEAK (in MW)

		FARM	NON-FARM RESIDENTIAL	COMMERCIAL	MINING	INDUSTRIAL	STREET & HIGHWAY LIGHTING	OTHER	SYSTEM TOTALS	Calculated System Totals
Last Year Peak Day	2017									0.0

7610.0310 Item D. PEAK DEMAND BY MONTH FOR THE LAST CALENDAR YEAR (in MW)

		JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER
Last Year	2017	228.4	209.4	197.4	190.9	229.1	284.9	318.7	290.8	306.8	207.3	206.0	223.5

COMMENTS
MMPA is requesting an exemption from Item C of this page, as it does not possess the information necessary to classify the system peak by class of service. The Agency sells all of its power and energy to its member utilities at wholesale. The peak demand presented in Item D includes 2.3% transmission system losses.

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

7610.0310 Item E. PART 1: FIRM PURCHASES (Express in MW)

			NAME OF OTHER UTILITY =>							
Past Year	2017	Summer								
		Winter								
Present Year	2018	Summer								
		Winter								
1st Forecast Year	2019	Summer								
		Winter								
2nd Forecast Year	2020	Summer								
		Winter								
3rd Forecast Year	2021	Summer								
		Winter								
4th Forecast Year	2022	Summer								
		Winter								
5th Forecast Year	2023	Summer								
		Winter								
6th Forecast Year	2024	Summer								
		Winter								
7th Forecast Year	2025	Summer								
		Winter								
8th Forecast Year	2026	Summer								
		Winter								
9th Forecast Year	2027	Summer								
		Winter								
10th Forecast Year	2028	Summer								
		Winter								
11th Forecast Year	2029	Summer								
		Winter								
12th Forecast Year	2030	Summer								
		Winter								
13th Forecast Year	2031	Summer								
		Winter								
14th Forecast Year	2032	Summer								
		Winter								

COMMENTS

The Agency Does not Have any Firm Purchases from Other Utilities

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

7610.0310 Item E. PART 2: FIRM SALES (Express in MW)

NAME OF OTHER UTILITY =>									
Past Year	2017	Summer							
		Winter							
Present Year	2018	Summer							
		Winter							
1st Forecast Year	2019	Summer							
		Winter							
2nd Forecast Year	2020	Summer							
		Winter							
3rd Forecast Year	2021	Summer							
		Winter							
4th Forecast Year	2022	Summer							
		Winter							
5th Forecast Year	2023	Summer							
		Winter							
6th Forecast Year	2024	Summer							
		Winter							
7th Forecast Year	2025	Summer							
		Winter							
8th Forecast Year	2026	Summer							
		Winter							
9th Forecast Year	2027	Summer							
		Winter							
10th Forecast Year	2028	Summer							
		Winter							
11th Forecast Year	2029	Summer							
		Winter							
12th Forecast Year	2030	Summer							
		Winter							
13th Forecast Year	2031	Summer							
		Winter							
14th Forecast Year	2032	Summer							
		Winter							

COMMENTS

The Agency Does not Have any Firm Sales to Other Utilities

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

7610.0310 Item F. PART 1: PARTICIPATION PURCHASES (Express in MW)

		NAME OF OTHER UTILITY =>	Short Term Capacity Purchases							
Past Year	2017	Summer	10							
		Winter	10							
Present Year	2018	Summer	5							
		Winter	5							
1st Forecast Year	2019	Summer	70							
		Winter	70							
2nd Forecast Year	2020	Summer	65							
		Winter	65							
3rd Forecast Year	2021	Summer	70							
		Winter	70							
4th Forecast Year	2022	Summer	75							
		Winter	75							
5th Forecast Year	2023	Summer	80							
		Winter	80							
6th Forecast Year	2024	Summer	85							
		Winter	85							
7th Forecast Year	2025	Summer	90							
		Winter	90							
8th Forecast Year	2026	Summer	90							
		Winter	90							
9th Forecast Year	2027	Summer	95							
		Winter	95							
10th Forecast Year	2028	Summer	100							
		Winter	100							
11th Forecast Year	2029	Summer	105							
		Winter	105							
12th Forecast Year	2030	Summer	0							
		Winter	0							
13th Forecast Year	2031	Summer	0							
		Winter	0							
14th Forecast Year	2032	Summer	0							
		Winter	0							

COMMENTS

This spreadsheet reflects transactions entered into as of 7/15/18. Short term capacity purchases from several counterparties are aggregated for limited disclosure. The data reported for each season follows MISO's planning year construct because it is according to that construct that MMPA purchases capacity. Under that construct -- and as reported here -- summer of a given planning year corresponds to June-November of that year, and winter of a given planning year corresponds to December of that year through May of the next year.

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

7610.0310 Item F. PART 2: PARTICIPATION SALES (Express in MW)

			NAME OF OTHER UTILITY =>							
Past Year	2017	Summer								
		Winter								
Present Year	2018	Summer								
		Winter								
1st Forecast Year	2019	Summer								
		Winter								
2nd Forecast Year	2020	Summer								
		Winter								
3rd Forecast Year	2021	Summer								
		Winter								
4th Forecast Year	2022	Summer								
		Winter								
5th Forecast Year	2023	Summer								
		Winter								
6th Forecast Year	2024	Summer								
		Winter								
7th Forecast Year	2025	Summer								
		Winter								
8th Forecast Year	2026	Summer								
		Winter								
9th Forecast Year	2027	Summer								
		Winter								
10th Forecast Year	2028	Summer								
		Winter								
11th Forecast Year	2029	Summer								
		Winter								
12th Forecast Year	2030	Summer								
		Winter								
13th Forecast Year	2031	Summer								
		Winter								
14th Forecast Year	2032	Summer								
		Winter								

COMMENTS
The Agency Does not Have any Participation Sales

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

7610.0310 Item G. LOAD AND GENERATION CAPACITY (Express in MW)

			Column 1	Column 2	Column 3	Column 4	Column 5	Column 6	Column 7	Column 8	Column 9	Column 10	Column 11	Column 12	Column 13	Column 14	Column 15
			SEASONAL MAXIMUM DEMAND	SCHEDULE L PURCHASE AT THE TIME OF SEASONAL SYSTEM DEMAND	SEASONAL SYSTEM DEMAND	ANNUAL SYSTEM DEMAND	SEASONAL FIRM PURCHASES (TOTAL)	SEASONAL FIRM SALES (TOTAL)	SEASONAL ADJUSTED NET DEMAND (3 - 5 + 6)	ANNUAL ADJUSTED NET DEMAND (4 - 5 + 6)	NET GENERATING CAPABILITY	PARTICIPATION PURCHASES (TOTAL)	PARTICIPATION SALES (TOTAL)	ADJUSTED NET CAPABILITY (9 + 10 - 11)	NET RESERVE CAPACITY OBLIGATION	TOTAL FIRM CAPACITY OBLIGATION (7 + 13)	SURPLUS (+) OR DEFICIT (-) CAPACITY (12 - 14)
Past Year	2017	Summer	319		319	319			319	319	353	10		363	27	346	17
		Winter	228		228	319			228	319	353	10		363	19	248	115
Present Year	2018	Summer	330		330	330			330	330	356	5		361	28	358	3
		Winter	298		298	330			298	330	356	5		361	25	323	39
1st Forecast Year	2019	Summer	406		406	406			406	406	364	70		434	34	440	-7
		Winter	301		301	406			301	406	364	70		434	25	326	108
2nd Forecast Year	2020	Summer	410		410	410			410	410	364	65		429	34	445	-16
		Winter	303		303	410			303	410	364	65		429	25	329	100
3rd Forecast Year	2021	Summer	414		414	414			414	414	364	70		434	35	449	-15
		Winter	306		306	414			306	414	364	70		434	26	332	102
4th Forecast Year	2022	Summer	418		418	418			418	418	364	75		439	35	453	-14
		Winter	308		308	418			308	418	364	75		439	26	334	104
5th Forecast Year	2023	Summer	421		421	421			421	421	364	80		444	35	456	-13
		Winter	311		311	421			311	421	364	80		444	26	337	107
6th Forecast Year	2024	Summer	424		424	424			424	424	364	85		449	38	460	-11
		Winter	313		313	424			313	424	364	85		449	26	340	109
7th Forecast Year	2025	Summer	427		427	427			427	427	364	90		454	36	463	-10
		Winter	316		316	427			316	427	364	90		454	27	342	112
8th Forecast Year	2026	Summer	430		430	430			430	430	364	90		454	36	467	-13
		Winter	318		318	430			318	430	364	90		454	27	345	109
9th Forecast Year	2027	Summer	434		434	434			434	434	364	95		459	36	470	-11
		Winter	320		320	434			320	434	364	95		459	27	347	111
10th Forecast Year	2028	Summer	437		437	437			437	437	364	100		464	37	473	-10
		Winter	322		322	437			322	437	364	100		464	27	349	114
11th Forecast Year	2029	Summer	440		440	440			440	440	364	105		469	37	477	-8
		Winter	325		325	440			325	440	364	105		469	27	352	117
12th Forecast Year	2030	Summer	443		443	443			443	443	364	0		364	37	480	-116
		Winter	327		327	443			327	443	364	0		364	27	354	9
13th Forecast Year	2031	Summer	445		445	445			445	445	364	0		364	37	483	-119
		Winter	329		329	445			329	445	364	0		364	28	357	7
14th Forecast Year	2032	Summer	448		448	448			448	448	364	0		364	36	486	-123
		Winter	331		331	448			331	448	364	0		364	28	359	5

COMMENTS

Seasonal Demands as shown include 2.3% Transmission System Losses. Net Generating capability accounts for EFORDs. Assumption for Net Reserve Capacity Obligation is 8.4%.

The summer demand reported here for a given year corresponds to MMPA's summer peak demand of that year. The winter demand reported for a given year is MMPA's peak demand for the winter season beginning in November of that year and extending into the next year.

As requested in DOC instructions, we report MMPA's maximum seasonal demand here. In MMPA's IRP, in accordance with MISO requirements, we report MMPA's Coincident Peak (CP) with MISO at the time of MISO's annual peak. Per MISO requirements, MMPA's capacity requirements, as reported in the IRP, are based upon MMPA's CP with MISO. Therefore, the capacity obligation reported here (based upon MMPA's NCP) differs from that reported in MMPA's IRP.

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

7610.0310 Item H. ADDITIONS AND RETIREMENTS (Express in MW)

		ADDITIONS	RETIREMENTS
Past Year	2017		
Present Year	2018		
1st Forecast Year	2019		
2nd Forecast Year	2020		
3rd Forecast Year	2021		
4th Forecast Year	2022		
5th Forecast Year	2023		
6th Forecast Year	2024		
7th Forecast Year	2025		
8th Forecast Year	2026		
9th Forecast Year	2027		
10th Forecast Year	2028		
11th Forecast Year	2029		
12th Forecast Year	2030		
13th Forecast Year	2031		
14th Forecast Year	2032		

COMMENTS
The Agency Does not Have any Additions and Retirments

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

Please use the appropriate code for the fuel type as shown in the list at the bottom of the worksheet.

		FUEL TYPE 1		FUEL TYPE 2		FUEL TYPE 3		FUEL TYPE 4		FUEL TYPE 5		FUEL TYPE 6	
		Name of Fuel	NG	Name of Fuel	FO2	Name of Fuel		Name of Fuel		Name of Fuel		Name of Fuel	
		Unit of Measure	MMBtu	Unit of Measure	MMBtu	Unit of Measure		Unit of Measure		Unit of Measure		Unit of Measure	
		QUANTITY OF FUEL USED	NET MWH GENERATED	QUANTITY OF FUEL USED	NET MWH GENERATED	QUANTITY OF FUEL USED	NET MWH GENERATED	QUANTITY OF FUEL USED	NET MWH GENERATED	QUANTITY OF FUEL USED	NET MWH GENERATED	QUANTITY OF FUEL USED	NET MWH GENERATED
Past Year	2017	4,778,291	647,224	-	-								
Present Year	2018	3,996,532	548,840	19,250	2,500								
1st Forecast Year	2019	3,996,532	548,840	19,250	2,500								
2nd Forecast Year	2020	4,006,935	550,285	19,250	2,500								
3rd Forecast Year	2021	3,996,532	548,840	19,250	2,500								
4th Forecast Year	2022	3,996,532	548,840	19,250	2,500								
5th Forecast Year	2023	3,996,532	548,840	19,250	2,500								
6th Forecast Year	2024	4,006,935	550,285	19,250	2,500								
7th Forecast Year	2025	3,996,532	548,840	19,250	2,500								
8th Forecast Year	2026	3,996,532	548,840	19,250	2,500								
9th Forecast Year	2027	3,996,532	548,840	19,250	2,500								
10th Forecast Year	2028	4,006,935	550,285	19,250	2,500								
11th Forecast Year	2029	3,996,532	548,840	19,250	2,500								
12th Forecast Year	2030	3,996,532	548,840	19,250	2,500								
13th Forecast Year	2031	3,996,532	548,840	19,250	2,500								
14th Forecast Year	2032	4,006,935	550,285	19,250	2,500								

LIST OF FUEL TYPES

BIT - Bituminous Coal
COAL - Coal (general)
DIESEL - Diesel
FO2 - Fuel Oil #2 (Mid-distillate)
FO6 - Fuel Oil #6 (Residual fuel oil)
LIG - Lignite
LPG - Liquefied Propane Gas
NG - Natural Gas
NUC - Nuclear
REF - Refuse, Bagasse, Peat, Non-wo
STM - Steam
SUB - Sub-bituminous coal
HYD - Hydro (water)
WIND - Wind
WOOD - Wood
SOLAR - Solar

COMMENTS

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

7610.0500 TRANSMISSION LINES

Subpart 1. **Existing transmission lines.** Each utility shall report the following information in regard to each transmission line of 200 kilovolts now in existence:

A. a map showing the location of each line;
B. the design voltage of each line;
C. the size and type of conductor;
D. the approximate location of d.c. terminals or a.c. substations; and
E. the approximate length of each line in Minnesota.

Subpart 2. **Transmission line additions.** Each generating and transmission utility, as defined in part 7610.0100, shall report the information required in subpart 1 for all future transmission lines over 200 kilovolts that the utility plans to build within the next 15 years.

Subpart 3. **Transmission line retirements.** Each generating and transmission utility, as defined in part 7610.0100, shall identify all present transmission lines over 200 kilovolts that the utility plans to retire within the next 15 years.

In Use (enter X for selection)	To Be Built (enter X for selection)	To Be Retired (enter X for selection)	DESIGN VOLTAGE	SIZE OF CONDUCTOR	TYPE OF CONDUCTOR	D.C. OR A.C. (specify)	LOCATION OF D.C. TERMINALS OR A.C. SUBSTATIONS	INDICATE YEAR IF "TO BE BUILT" OR "RETIRED"	LENGTH IN MINNESOTA (miles)

COMMENTS
MMPA does not own, nor does it expect to own during the forecast period, any transmission lines above 200 kilovolts.

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

7610.0600, item A. 24 - HOUR PEAK DAY DEMAND

Each utility shall provide the following information for the last calendar year:

A table of the demand in megawatts by the hour over a 24-hour period for:

1. the 24-hour period during the summer season when the megawatt demand on the system was the greatest; and
2. the 24-hour period during the winter season when the megawatt demand on the system was the greatest

	DATE	DATE	
	7/17/17	1/4/17	<= ENTER DATES
TIME OF DAY	MW USED ON SUMMER PEAK DAY	MW USED ON WINTER PEAK DAY	
0100	169	164	
0200	159	160	
0300	153	159	
0400	151	160	
0500	152	163	
0600	163	175	
0700	181	197	
0800	207	213	
0900	223	214	
1000	238	214	
1100	254	215	
1200	271	212	
1300	283	210	
1400	295	209	
1500	307	207	
1600	314	208	
1700	318	214	
1800	319	228	
1900	314	227	
2000	305	224	
2100	292	218	
2200	276	206	
2300	245	191	
2400	214	177	

COMMENTS
MMPA's reported MW include 2.3% transmission system losses.

Appendix C. Renewable Energy Standard Rate Impact Report

This appendix contains MMPA's rate impact report for complying with the Renewable Energy Standards (RES) in Minnesota Statute §216B.1691.

Rate Impact Follows the PUC Established Methodology

MMPA's RES rate impact calculations in this appendix follow the PUC established methodology.

Minnesota Statute §216B.1691 establishes a Renewable Energy Standard and requires a utility to evaluate the rate impact of the standard and file the report as an appendix in its resource plan. On January 6, 2015, the Minnesota Public Utilities Commission (PUC) issued Order Establishing Uniform Reporting System for Estimating Rate Impact of Minn. Stat. §216B.1691 ("Order") under Docket No. E-999/CI-11-852.

Levelized Historic RES Rate Impact Was 0.25 cents/kWh

MMPA's historic RES rate impact was evaluated for the years 2005 to 2017. On an annualized basis, the RES rate impact ranged from 0.00 to 0.96 cents per kWh. The levelized RES rate impact for this time period was 0.25 cents per kWh. Full details are provided in the historic table below.

The years analyzed satisfies Order point 2A(1) directing an analysis for the period 2005 until the last reported year.

Levelized RES Rate Impact Projected to be 0.03 cents/kWh

The RES rate impact was projected for the years 2018 to 2033. On an annualized basis, the RES rate impact is projected to range from 0.64 to (0.53) cents per kWh. The levelized RES rate impact for this time period is projected to be 0.03 cents per kWh. Full details are provided in the projection table below.

The years analyzed satisfies Order point 2A(2) directing an analysis of the 15 years following the last reported year.

Includes All Generation Assets that Comply with the Renewable Energy Standard

MMPA's rate impact analysis includes all its generation assets that meet the renewable energy standard regardless of when the asset was acquired.

The resources included in the evaluation satisfy the requirement of Order point 2B.

Rate Impact Includes Direct Costs

The RES rate impact calculations include direct costs incurred to meet the RES. These costs include power purchase agreements (PPAs) from renewable resources and the capital and operating costs of owned assets. There were no transmission costs to include in the rate impact.

The direct costs included satisfy Order points 2C and 2E.

Rate Impact Includes Avoided Costs

The RES rate impact calculations include avoided energy, capacity, and emissions costs. There were no avoided transmission costs included in the rate impact.

Historically, the avoided energy costs are those associated with MMPA's PPAs and owned assets. The projected avoided energy costs are based on locational marginal prices for Minnesota Hub, escalated at inflation. The avoided capacity costs are based on the MISO Zone 1 Cost of New Entry (CONE), escalated at inflation.

The avoided regulatory cost of emissions is included and based on the June 6, 2018 PUC Order Establishing 2018 and 2019 Estimate of Future CO_2 Regulation Costs. These costs are included starting in 2025 and estimated at the midpoint of the regulatory costs, increased at inflation.

The avoided costs accounted for in the RES rate impact are in compliance with Order points 2F and 2G(2).

Rate Impact Excludes Costs for Ancillary Services and Base Load Cycling

The RES rate impact does not include the indirect costs of ancillary services or base load cycling that are a result of the increase in intermittent generation resources on the system. Based on MISO's market construct, MMPA sells all generation output to, and procures all their load from, the MISO market. MISO charges for ancillary services and base load cycling cannot be attributed to the RES resources.

This analysis meets the requirements of Order point 2D.

RES Rate Impact Summary Tables

The tables below detail the historic and projected RES rate impact. They report annualized and levelized cost impacts, satisfying Order point 2H.

MMPA RES Rate Impact – Historical (2005-2017)

[TRADE SECRET DATA BEGINS

TRADE SECRET DATA ENDS]

MMPA RES Rate Impact – Projected (2018-2033)

[TRADE SECRET DATA BEGINS

TRADE SECRET DATA ENDS]

Appendix D. Regulatory Requirements Cross Reference Index

The following table provides a cross reference index for the various regulatory requirements related to Integrated Resource Plan filings.

Statute or Rule	Description of Requirement	Location in IRP
7843.0400 Subp. 1	Include most Advance Forecast filed with DOC	Appendix B
7843.0400 Subp. 2	File a proposed plan for meeting the service needs of its customers	Sections 7 and 10
7843.0400 Subp. 3A	Describe resource options considered, including information supporting selection of proposed resources	Section 9 and 11
7843.0400 Subp. 3B	Include descriptions of the overall process and of the analytical techniques used to create resource plan from available options	Section 11
7843.0400 Subp. 3C	Include a five-year action plan	Section 10
7843.0400 Subp. 3D	Explain why the plan is in the public interest	Section 13
7843.0400 Subp. 4	Include a non-technical summary	Section 1
216B.1691 Subd. 2e	Rate impact of compliance with Renewable Energy Standard	Section 12 and Appendix C
216B.1691 Subd. 3	Description of efforts towards meeting REO/RES	Section 12
216B.2422 Subd. 2	Include a least cost plan for meeting 50% and 75% of all energy needs from new and refurbished generating facilities through a combination of conservation and renewable energy resources	Section 12
216B.2422 Subd. 2c	Narrative on utility's progress towards achieving the state greenhouse gas emission reduction goals	Section 12
216B.2422 Subd. 3	Use Commission values and other external factors including socioeconomic costs when evaluating and selecting resource options	Section 11

Appendix E. Acronyms Index

The following index provides definitions of acronyms used in this IRP.

Acronym	Definition
AC	Alternating current
BOGF	Black Oak Getty Wind Farm
BSF	Buffalo Solar Facility
CAGR	compounded annual growth rates
CDD	Cooling degree day
CIP	Conservation Improvement Program
CP	Coincident peak
DIR	Dispatchable Intermittent Resource
DOC	Department of Commerce
EFORd	Equivalent demand forced outage rate
EIA	Energy Information Administration
EPA	Environmental Protection Agency
ERMU	Elk River Municipal Utilities
FEP	Faribault Energy Park
FERC	Federal Energy Regulatory Commission
GOR	Gross operating revenue
GW	Gigawatt
GWh	Gigawatt-hour
HDD	Heating degree day
HTBE	Hometown BioEnergy
ICAP	Installed capacity
IRP	Integrated resource plan
kW	Kilowatt
kWh	Kilowatt-hour
LBA	Local balancing area
LNG	Liquified natural gas
MATS	Mercury and Air Toxics Standards
MISO	Midcontinent Independent System Operator
MMPA	Minnesota Municipal Power Agency

MRS	Minnesota River Station
MW	Megawatt
MWh	Megawatt-hour
NOAA	National Oceanic and Atmospheric Administration
NCP	Non-coincident peak
OGWF	Oak Glen Wind Farm
PPA	Power purchase agreement
ppb	Parts per billion
PRM	Planning reserve margin
PRMR	Planning resource margin requirements
PUC	Public Utilities Commission
PY	Planning year (June 1 through May 31)
REC	Renewable energy credit
RES	Renewable energy standard
SEP	Shakopee Energy Park
UCAP	Unforced capacity
WAPA	Western Area Power Administration
ZRC	Zonal resource credits

Shakopee Public Utilities

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DATE: March 1, 2022

TO: SPU Commissioners

FROM: Greg Drent, General Manager

Subject: Smart Switch Program

At SPU's last commission meeting, there was a discussion on the Smart Switch Program. This memo outlines the program in detail. The Smart Switch Program launched at SPU in 2003. The program helps reduce electricity demand during June, July, and August when temperatures and humidity levels are high and SPU is at its peak demand. Participants enrolled in the program receive a credit of $12.00 a year on their electricity bills. The demand charges to SPU from our wholesale power contract can have a savings of $9,781.00 a month during June, July, and August with current number of customers participating.

Smart Switches are devices on the side of the house that cycle the AC unit in the home. The program cycles the AC in the home for a total of 20 min out of every hour that the system is activated. Not all units can be turned off at once; otherwise, we could not cycle them, and the temperature rise in the home would be too great. When the system is activated, they are divided into three zones. A signal is sent to the device to open the communication to the AC unit from the thermostat. This is no different than if the homeowner were to turn off their AC unit. SPU has 1,903 Smart Switch customers and can save as much as 1kw per unit.

The electric department manages the analysis for when to activate load controls. They monitor the system load to determine when SPU is getting close to its peak loading for the month. When it is getting close for the month, they run load control and set the peak. Brad Carlson and I provide the final decision on when to run load control.

If a customer enrolled in the Smart Switch program sells the home, new homeowners are automatically enrolled in the program, unless they request the load control to be disconnected. SPU hires an electrician to remove the device and return it to SPU when we receive requests for removal.

Below is a cost estimate to administer the Smart Switch Program.

Rebate to 1,903 customers = $22,836.00
Software maintenance = $10,500.00
American Messaging for sending signal = $18,568.00
Total =$51,904.00
Savings on MMPA bill of $29,343.00

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Option 1: Discontinue the program in 2023, as it does not make sense financially.

Option 2: Keep the program running and do not rebate the customers any amount in 2023 so the program is profitable.

Option 3: Keep program and try to get more customers, to at least 7500, to make the program profitable

Action:

Direct staff on future of smart switch program.