AGENDA
SHAKOPEE PUBLIC UTILITIES COMMISSION
REGULAR MEETING
MAY 6, 2019

1. **Call to Order** at 5:00pm in the SPUC Service Center, 255 Sarazin Street.

2. **Approval of Minutes**

3. **Communications**

4. **Approve the Agenda**

5. **Approval of Consent Business**

6. **Bills: Approve Warrant List**

7. **Liaison Report**

8. **Reports: Water Items**
   8a) Water System Operations Report – Verbal
   8b) SPU and City Staff Meeting – Water Supply Planning Coordination
   8c) Resn. #1246 – Adopting the Bid Amount and Contract Award for the Watermain Replacement in the 2019 City of Shakopee Street Reconstruction Project

9. **Reports: Electric Items**
   9a) Electric System Operations Report – Verbal
   9b) Resn. #1245 – Approving Shakopee Public Utilities Commission's Cogeneration and Small Power Production Tariff
   9c) APPA Certificate of Excellence in Reliability Award
   9d) 2019 Reliability and Outage Report - Presentation
   9e) MMPA Board Meeting Summary – April 2019

10. **Reports: Human Resources**
    10a) SPU Employee Total Compensation Reports

11. **Reports: General**
    11a) MMUA Tom Bovitz Scholarship Essays - Update
    11b) Insurance Liability Coverage – Waiver
    11c) MMUA Resource Article
    11d) 2019 Commission Goals and Objectives

12. **New Business**

13. **Tentative Dates for Upcoming Meetings**
    - Mid Month Meeting -- May 20
    - Regular Meeting -- June 3
    - Mid Month Meeting -- June 17
    - Regular Meeting -- July 1

14. **Adjourn** to 5/20/19 at the SPU Service Center, 255 Sarazin Street

MINUTES

OF THE

SHAKOPEE PUBLIC UTILITIES COMMISSION
(Regular Meeting)

President Joos called the regular session of the Shakopee Public Utilities Commission to order at the Shakopee Public Utilities meeting room at 5:00 P.M., April 15, 2019.

MEMBERS PRESENT: Commissioners Joos, Amundson, Meyer, Clay and Mocol. Also present, Liaison Lehman, Utilities Manager Crooks, Finance Director Schmid, Planning & Engineering Director Adams, Electric Superintendent Drent and Water Superintendent Schemel.

Motion by Amundson, seconded by Meyer to approve the minutes of the April 1, 2019 Commission meeting. Motion carried.

There were no Communication items to report.

President Joos offered the agenda for approval. It was stated that agenda Item 11b: 2018 Audit of Financial Statements will be moved in the agenda directly after Item7: Liaison Report

Motion by Amundson, seconded by Clay to approve the amended agenda as presented. Motion carried.

There was no consent business.

The warrant listing for bills paid April 15, 2019 was presented.

Motion by Meyer, seconded by Mocol to approve the warrant listing dated April 15, 2019 as presented. Motion carried.

Steve Wischmann from bergenKDV presented the 2018 SPU Audit of Financial Statements. An unmodified, clean opinion was given. There were no material weaknesses or significant deficiencies. Financial reserves and net positions were discussed.

Motion by Meyer, seconded by Amundson to accept the 2018 SPU Audit of Financial Statements. Motion carried.

Water Superintendent Schemel provided a report of current water operations. A quarterly update on the Department's programs was presented.

Mr. Schemel presented the Commission with the procedures and protocol that is followed in regards to Nitrate sampling and data collection, as approved by the Commission in 2005. A historical review of all Shakopee wells was also provided.

Utilities Manager Crooks reviewed the SPU responses to the City Administrator's letter to the Commission dated March 25, 2019. Staff provided responses to 21 comments within the letter. The Commission agreed to send the responses back to the City.

Liaison Lehman took his seat. The City Council has forwarded the City of Shakopee 2040 Comprehensive Plan to the Met Council. However, the plan will be updated with the completion of the AUAR.

Electric Superintendent Drent provided a report of current electric operations. Two electric outages were reviewed, one caused by a raccoon and the other was a faulty transformer. The high wind event of April 11 was reviewed. Construction projects were updated.

Mr. Drent reviewed the 2019 APPA Lineworker's Rodeo in Colorado Springs and provided the results of the SPU teams. Three SPU apprentice lineworkers finished in the top 15%, out of 130 entrants. The journeyman teams also competed very well, with our best team finishing 15th out of 78 teams. SPU had the top journeyman and top apprentice in the State of Minnesota.

Planning and Engineering Director Adams reviewed the Minnesota distributed generation mandate and process requirements. The mandate has a compliance deadline of June 17, 2019.

Motion by Clay, seconded by Mocol to offer Resolution #1243. A Resolution Adopting Shakopee Public Utilities Commission's Policy Regarding Distributed Generation Resources and New Metering and Rules Governing the Interconnection of Cogeneration and Small Power Production Facilities. It was discussed that the term City Council be removed from paragraph #15 in the Policy and Rules. Ayes: Commissioners Clay, Mocol, Meyer, Amundson and Joos. Nay: none. Motion carried. Resolution passed.

Motion by Amundson, seconded by Meyer to offer Resolution #1244. A Resolution Adopting the Shakopee Public Utilities Commission Distributed Energy Resource Interconnection Process. It was requested to add the effective date of June 3 to the motion. Ayes: Commissioners Meyer, Mocol, Amundson, Clay and Joos. Nay: none. Motion carried. Resolution passed.

Discussion regarding Resolution #1245 – Approving Shakopee Public Utilities Commission's Cogeneration and Small Power Production Tariff took place. Commission consensus was to make a best faith effort to inform existing and potential solar customers of the proposed change in rate.

Motion by Mocol, seconded by Clay to table any action on Resolution #1245 until the May 6 Commission meeting. Motion carried.

Mr. Crooks announced that the MMUA Tom Bovitz Scholarship Essay winner for 2019 is Shelby Zander.

Finance Director Schmid presented the 2019 March financial results.

The tentative commission meeting dates of May 6 and May 20 were noted.

Motion by Meyer, seconded by Mocol to adjourn to the May 6, 2019 meeting. Motion carried.

Commission Secretary: John R. Crooks

8b

SHAKOPEE PUBLIC UTILITIES
MEMORANDUM

TO: John Crooks, Utilities Manager JDC

FROM: Joseph D. Adams, Planning & Engineering Director JD Adams

SUBJECT: Staff Meeting with City Engineering and Planning

DATE: May 2, 2019

ISSUE

Water Superintendent Lon Schemel, Project Engineer Christian Fenstermacher and I met on April 22nd with city staff including City Engineer Steve Lillihaug, Community Development Director Michael Kerski and City Planner Joe Widing to review the Utilities Commission's responses to the City Administrator's comments/questions/concerns regarding the Commission's current Water Supply Plan and 2018 Comprehensive Water Plan.

BACKGROUND

City Administrator William Reynolds letter addressed to the Utilities Commission dated Mach 25th listed 21 points of discussion that were addressed by Utilities Manager John Crooks in the Utilities Commission's response approved at their April 15th meeting.

DISCUSSION

Attached is a copy of the Utilities Commission's responses annotated in red with the agreed upon direction determined at the meeting with city staff. Overall the meeting went quite well in my opinion and information exchange is proceeding as outlined.

REQUESTED ACTION

This is information item and no action is being requested at this time.

1. ***Current Shakopee population is incorrect. Stated as "approximately 37,000", this number reflects 2010 census data. This number should be the latest Metropolitan Council estimate for 2017, which is 41,519***

   -This population was listed in a general introduction paragraph, historical population data is reflected in table 3-1 which lists a 2017 population of 41,374, which is consistent with current estimates. Data included in table 3-1 was utilized in the report.

TO BE REVISED WITH THE AUAR REPORT

2. ***On page 13, Table 3-2 "Projected Population Data" is not consistent with revised City or Met Council projections for city population, please refer to the following table for consistent information.***

   -At the time of development of this plan, recently provided population information was not available, data from met council available at that time was referenced, water use projections can be updated with newly provided population information as needed.

TO BE REVISED WITH THE AUAR REPORT

3. ***Existing and projected land use maps and table should be revised to remain consistent with the City's 2040 Comprehensive Plan land use maps and tables.***

   -Maps utilized in the comp water plan were the most current at the time of development - the water plan can be updated to utilize these more recently updated maps as they are available. ***Table B-1 through B-5 "Projected Water Consumption by Land Use" need to be revised to reflect correct planned land use categories as defined in the 2040 Comprehensive Plan and correct full build-out acreage for these planned categories. Information on these tables appears to be from the 2030 Comprehensive Plan which will not be in effect once the 2040 Plan is adopted.***

   -Maps utilized in the comp water plan were the most current at the time of development - the water plan can be updated to utilize these more recently updated maps as they are available. ***Figure 2-3 "Existing Water System Model Map" and Figure 3-1 "Existing Land Use" do not include the new Windermere development, this should be included in both maps.***

   -The existing water system map was developed with current water mapping information at the time of development in 2017. Given the passage of time, new water main has since been added. This additional water main can be included in any updates completed to the comprehensive water plan.

IN PROCESS FROM SEH

4. ***Page ES-I - The Existing Facilities inventory does not match the Water Supply Plan inventory in Table 5 of that plan.***

   -The water supply plan (DNR) was due in October of 2017 and was completed a year before the comprehensive water plan. Both plans inventory a total storage capacity of 11.25 MGD. the 2017 water supply plan (table 5) listed tank 5 as an elevated tank. Though it functions as an elevated tank with "floating storage", as all tanks in the SPUC system function, it is constructed at grade and thus is listed as a ground storage tank in the comprehensive water plan.

TO BE REVISED

5. ***Page ES-1 - 8 million gallons in well capacity plus 11.25 MG in storage is a substantial amount over the historic maximum day demand.***

   -The sizing requirements for supply and storage are provided in great detail within the comprehensive water plan:

   The year 2012 had a maximum day demand of 16.26 MGD. Water supply capacity from wells are sized to

satisfy max day demand in each pressure zone, with the two largest wells offline (for the total system, firm capacity is 20.3 mgd vs 24.4 mgd total) The trigger chart provided in section 7.6 of the comprehensive water plan recommends a new well be constructed when max day demand has the potential to approach 20.3 mgd. Given the time it takes to develop and place a new well online (in relation to site and production procurement, permitting, design and commissioning) proactive planning is required.
With regards to storage, each pressure zone is assessed in relation to the storage needs of that zone. Given the pattern of development with the City first developing at lower elevations and then moving south to higher elevations, additional pressure zones have been created with their own unique storage needs. For many of the water storage performance metrics, higher elevation pressure zones do not have regular access to water stored in lower pressure zones, except for if it is pumped from a booster station. The ability of each pressure zone to receive water thorough booster stations from lower pressure zones was accounted for in the storage analysis for each pressure zone. While indeed it could be asserted that SPUC has ample water storage available, the development of expanded pressure zones have additional storage recommendations that are not satisfied by existing storage facilities within lower pressure zones

DISCUSSED AND EXPLAINED AT COORDINATION MEETING

6. Discussion topic for a water treatment plant.

DISCUSSED AND EXPLAINED AT COORDINATION MEETING

7. Provide appendices for the Comp Plan.

SENT APPENDICIES FOR WATER SUPPLY PLAN AND 2018 COMPREHENSIVE WATER PLAN

8. Manganese guidance level.

TO BE DISCUSSED IN A FUTURE MEETING

9. There are 2,898 nitrate results on record since 2002. Nitrate results are presented to the Commission on a quarterly basis. The wells are not directly connected to the distribution/transmission system. They come together within the Pumphouse for treatment where they blend together before going to the distribution system.

DISCUSSED AND EXPLAINED AT COORDINATION MEETING

10. Discussion topic for ValleyFair! metering.

DISCUSSED AND EXPLAINED AT COORDINATION MEETING – NO PRIVATE WELLS

11. ***Table 5 - The ground vs. elevated inventory does not match the Comprehensive Plan inventory on page ES-1 of that plan.***
-The water supply plan (DNR) was due in October of 2017 and was completed a year before the comprehensive water plan. Both plans inventory a total storage capacity of 11.25 MGD, all of which is considered "floating storage" meaning, it can flow to the pressure zone that is served by gravity. the 2017 water supply plan (table 5) listed tank 5 as an elevated tank. Though it functions as an elevated tank with "floating storage", as all tanks in the SPUC system function, it is constructed at grade and thus is listed as a ground storage tank in the comprehensive water plan.

DISCUSSED AND EXPLAINED AT COORDINATION MEETING - TYPO

12. ***P. 14, last paragraph- Seems that 125.5 gallons per capita is an extremely high assumption that would lead too much of an overbuild of the system.***
    This figure, referenced in table 7 of the water supply plan is a system-wide per capita projection, so this figure accounts for all water use including, commercial, industrial, residential. This per capita figure is consistent with the historical total SPUC water system per capita water use (See table 2 of the water supply plan). With regards to only residential per capita water use, in recent years this figure has been in the range of 62-84 gallons per person per day, which is well within a normal range for residential users. This figure can vary depending on weather conditions which have a large effect on water use trends. A detailed summary of water use projection assumptions is included in the comprehensive water plan.

DISCUSSED AND EXPLAINED AT COORDINATION MEETING – ALL USAGE VS. RESIDENTIAL

13. Self-explanatory.

BOXES CHECKED INDICATE THAT THE UTILITY IS AWARE OF THESE CONCERNS DURING PLANNING

14. WHP possible coordination w/City as required by regulators.

CITY TO BE INVITED TO FUTURE GROUNDWATER GROUP MEETINGS

15. This plan was developed in 2016-2017, the CIP would be different.

DISCUSSED AND EXPLAINED AT COORDINATION MEETING

16. The Emergency Response Plan was given to ____________ on ____________.

EMAILED TO STEVE LILLEHAUG 5/1/19

17. Ordinances do not apply to SPU. The Water Policy Manual deals with water conservation.

POSSIBLE FUTURE CITY ORDINANCE/SPU POLICY ON WATER CONSERVATION

18. Discussion topic for AMI project.

DISCUSSED AND EXPLAINED AT COORDINATION MEETING

19. Same as above.
20. At the time of the report, rain barrels as an initiative was in planning but funding could not be secured from MetCouncil. SPU participated in the Clean Water Fund Water Efficiency Grant program with MetCouncil in 2016 and 2017. MetCouncil lost funding and the program stopped.

DISCUSSED AND EXPLAINED AT COORDINATION MEETING

21. TBD

SPU STAFF AGREED WITH CITY ABOUT BETTER EFFORTS FOR EDUCATING CUSTOMERS ON CONSERVATION ISSUES

8c

SHAKOPEE PUBLIC UTILITIES
MEMORANDUM

TO: John R. Crooks, Utilities Manager JRC

FROM: Lon R. Schemel, Water Superintendent

SUBJECT: **2019 City of Shakopee Street Reconstruction**

DATE: May 1, 2019

BACKGROUND

Resolution #262 defines the sequences involved in coordinating construction projects between the City of Shakopee and SPU. We are now at step 19 of that process which is the adoption of the bid amount and contract award.

ISSUE

On February 2, 2019, the SPU Commission adopted Resolution #1236 which ordered the project from the City of Shakopee for the areas involved to receive new watermain and appurtenances. In addition to this contract cost, other project costs include engineering and administration costs of 17% estimated at $22,288 and inspection costs to be determined. The amount approved in the 2019 budget for Reconstruction Projects is $450,000.

ACTION REQUESTED

Staff requests that the Commission adopt Resolution #1246 that approves the bid amount of $131,103 and contract award to Ryan Contracting for the 2019 City of Shakopee Street Reconstruction.

RESOLUTION #1246

A RESOLUTION TO ADOPT THE BID AMOUNT AND CONTRACT AWARD FOR THE WATERMAIN REPLACEMENT IN THE 2019 CITY OF SHAKOPEE STREET RECONSTRUCTION PROJECT

WHEREAS, the Shakopee City Council has accepted bids for the areas defined in the 2019 Street Reconstruction Project for street, sidewalk, sanitary sewer, storm sewer, curb and gutter, and

WHEREAS, the Shakopee Public Utilities Commission desires to replace the existing watermain, valves, hydrants, and service lines to the curb stop valve at cost to the Shakopee Public Utilities Commission, and

WHEREAS, the Shakopee Public Utilities Commission on February 4, 2019 ordered the project for watermain replacement, and

THEREFORE BE IT FURTHER RESOLVED, the funding for this project comes from the Commission approved reconstruction fund, and

WHEREAS, no costs for the street restoration are applied to the Shakopee Public Utilities Commission on this project.

NOW, THEREFORE BE IT RESOLVED BY THE SHAKOPEE PUBLIC UTILITIES COMMISSION THAT, in consideration of the savings and coordination the Shakopee Public Utilities Commission adopts the bid amount of $131,103.00 and contract award to Ryan Contracting for the 2019 City of Shakopee Street Reconstruction Project.

Adopted in regular session of the Shakopee Public Utilities Commission, this 6th day of May, 2019.

____

Commission President: Terrance Joos

ATTEST:

____

Commission Secretary: John R. Crooks

9b

SHAKOPEE PUBLIC UTILITIES
MEMORANDUM

TO: John Crooks, Utilities Manager JC

FROM: Joseph D. Adams, Planning & Engineering Director JDAdams

SUBJECT: Resolution #1245 and Customer Contacts re: New DER Tariff

DATE: May 2, 2019

ISSUE

Attached is a copy of the letter staff sent to the 42 customers who either currently have a distributed generation system interconnected with SPU's electric distribution system or have an application under review.

BACKGROUND

The Commission requested staff notify all of the existing distributed generation interconnected customers of the proposed new tariff to gather any comments/concerns prior to the new tariff taking effect.

DISCUSSION

To date there have been five customers who have inquired of staff what the difference for them will be from the old rate to the new rate and why there is proposed change. I interacted with three of the customers, Christian Fenstermacher interacted with two and you told me you had a conversation with one. These interactions have either been via email, telephone or in person. I have included the email interactions for the Commission to review.

REQUESTED ACTION

Staff is requesting the Commission adopt Resolution #1245 A Resolution Approving Shakopee Public Utilities Commission's Cogeneration and Small Power Production Tariff.

Note: the effective date of the new tariff will be July 1, 2019 and that will allow staff to provide for more than a 30 days' notice to all customers via our website and other means as determined by the Utilities Manager.

SHAKOPEE PUBLIC UTILITIES
"Lighting the Way – Yesterday, Today and Beyond"

April 26, 2019

Customer
Address
Shakopee, MN 55379

Dear Customer:

This is a notice that the Shakopee Public Utilities Commission (SPUC) intends to adopt the attached resolution that will modify the rate that you are credited at when your solar array produces more energy than you can consume locally and the excess is placed onto our distribution grid. Per state statutes, a municipal electric utility such as the SPUC may adopt its own policy, interconnection process, rules and tariffs for Distributed Energy Resources interconnected to the distribution system. The SPUC has always elected to do so and has recently modified its policy, process and rules to conform with changes to the applicable state statutes.

Now, the SPUC also plans to modify the tariff at their next regularly scheduled meeting on May 6, 2019 and provide for a 30-day notice period before the revised tariff will take effect. The SPUC is interested in any comments you may have as a customer with an approved interconnected Distributed Energy Resource system.

Please call or email us with your comments, questions and concerns by contacting Christian Fenstermacher Project Engineer at 952-345-2475, cfenstermacher@shakopeeutilities.com, or myself.

Thank you,

Joseph D. Adams
SPU Planning & Engineering
Director

jadams@shakopeeutilities.com
952-233-1501

Adams, Joe

To: DER Customer Number 3; Fenstermacher, Christian
Subject: RE: Modification of Renewable Energy Credit Rates

From: Adams, Joe
Sent: Thursday, May 2, 2019 11:58 AM
To: DER Customer Number 3 Fenstermacher, Christian <cfenstermacher@shakopeeutilities.com>
Subject: RE: Modification of Renewable Energy Credit Rates

Hello –

Was Schedule 1 also included? It has the calculated average retail rate for each customer class including residential. That is $0.1159 per kWh for 2019. The rate you are credited now is our residential rate of $0.988 per kwh, plus other factors including the variable power cost adjustment and the underground relocation charge which is currently $0.00034 per kWh.

The 2018 variable power cost adjustments per kWh were as follows:

Jan	0.0106
Feb	0.0137
Mar	0.0109
Apr	0.0103
May	0.0131
Jun	0.0225
Jul	0.0249
Aug	0.0198
Sep	0.0240
Oct	0.0191
Nov	0.0123
Dec	0.0118

So, up to now you were credited at the combined rate of the residential rate plus the variable power cost adjustment plus the underground relocation charge. As you can see in some months in 2018 that combined total was less than the new rate of $0.1159 and in some months it was greater. Depending on your systems production (usually higher in the summer months) and your usage (also usually higher in the summer months) the months when your system pushes power more to the grid than you are able to consume locally you may see either a slight gain or a slight decrease in the credit.

Most customers will see a small reduction in credits with this change in part because we were providing credits for the underground relocation charge that we should not have and in part because this way the effect of the power cost adjustment is averaged out over the entire year rather than month by month. Most likely you would push more power to the grid during the summer months when your system's production peaks, even though your own usage also peaks, because the difference usually results in a net output to our system. That is also when power costs are the highest and the power cost adjustment is higher, hence the potential for the credit to be higher.

The reason for the change is to comply with state requirements on how to treat net metering. The state has defined for all serving utilities how we shall calculate our average retail rates for each customer class for the purposes of net metering credits. We have to start with all revenue by customer class and then subtract our fixed monthly customer charges by customer class and other riders like our underground relocation charge and then divide that by total energy in kWh sales in each customer class to arrive at the rate we can reimburse for distributed generation sources connected to our distribution system.

If you like I could calculate what you received in 2018 and using the same 2018 data what you would have received using the new reimbursement rate, so you can see the difference.

Thank you,

Joe

Joseph D. Adams
SPU Planning & Engineering Director
jadams@shakopeeutilities.com
952-233-1501

From: **DER Customer Number 3**
Thursday, May 2, 2019 11:29 AM
To: Fenstermacher, Christian <cfenstermacher@shakopeeutilities.com>
Cc: Adams, Joe <jadams@shakopeeutilities.com>
Subject: Modification of Renewable Energy Credit Rates

Hi Christian,

We live in Shakopee and received a letter the other day notifying of SPUC intentions to adopt a resolution that will modify the rate at which we our credited when our solar array pushes power more to the grid than we are able to consume locally. The proposed 'Schedule 4 – Utility Avoided Energy, Capacity and Renewable Energy Credit Rates' were attached in the letter. Can you please send me the current rate credits for comparison? Also, what is reason for the modifications?

Thank you,

DER Customer Number 3

Adams, Joe

To: DER Customer Number 2
Subject: RE: Rate change for solar

From: Adams, Joe
Sent: Wednesday, May 1, 2019 3:16 PM
To: DER Customer Number 2
Subject: RE: Rate change for solar

DER Customer Number 2 –

Thank you for responding and asking these questions.

The short answer for A is our published residential retail rate is currently $0.0988 per kWh, and that is the base amount for which you are being paid for excess energy delivered to the utility in a given billing period. But, there are additional factors that are applied to your usage that are also taken into account when figuring out what you are credited in the event your system produces more than you consumed in a given billing period. These other factors include a variable power cost adjustment that fluctuates each billing period based on the monthly adjustment for the cost of purchased power charged to us by our wholesale power supplier and an underground relocation rate that is recalculated annually that is currently $0.00034 per kWh. For perspective, the 2018 variable power cost adjustments per kWh were as follows:

Jan	0.0106
Feb	0.0137
Mar	0.0109
Apr	0.0103
May	0.0131
Jun	0.0225
Jul	0.0249
Aug	0.0198
Sep	0.0240
Oct	0.0191
Nov	0.0123
Dec	0.0118

So, given that the variable power cost adjustment is not known in advance it is difficult to project if the sum of your annual credits would be higher under the new rate or lower. We could look at your account history and run a comparison using your 2018 data if you would like to get a better idea of how the change may affect you. Please let me know if you want us to do that.

For B, the rate you will be paid is on the attachment to the draft resolution and is referred to as our average retail rate for the prior year (2018) and will be recalculated each year. For 2019 that residential rate is $0.1159 per kWh. This rate is calculated by summing all electric revenue less fixed charges (the monthly service charge of $9.00) less the underground relocation fees and dividing by all energy usage within each customer class for the year. All electric revenue includes the revenue derived from the above described power cost adjustments.

For C, we currently do not have metering in place to collect more frequent data other than monthly readings of energy and demand, i.e. we do not have time of use metering in place. Consequently, we use the monthly readings for total energy received by the customer (supplied by the utility) and total energy delivered by the customer's system to the utility's distribution system and we then take the net difference in computing your billed or credited amount.

Thank you,

Joe

Joseph D. Adams
SPU Planning & Engineering Director
jadams@shakopeeutilities.com
952-233-1501

From: DER Customer Number 2
Sent: Monday, April 29, 2019 7:11 PM
To: Adams, Joe <jadams@shakopeeutilities.com>
Subject: Rate change for solar

Dear Mr. Adams,
We received a letter today from you indicating that there would be a change in how the Shakopee Utilities will be paying us for electricity that we produce above what we need. However the letter did not make it clear what the changes are to be. Can you please answer a few questions for us?
A) What is the current rate at which we are repaid?
B) What is to be the new rate?
C) Will you be averaging our production and our usage for the month or going hour by hour when figuring what we are producing and using?

We look forward to your reply.

DER Customer Number 2

Adams, Joe

To: DER Customer Number 1
Subject: RE: New Solar Rate

From: Adams, Joe
Sent: Wednesday, May 1, 2019 3:19 PM
To: DER Customer Number 1
Subject: New Solar Rate

We are compiling your data for the comparison and should have that ready tomorrow. I thought I would share with you now though the 2018 variable power cost adjustments per kWh were as follows:

Jan	0.0106
Feb	0.0137
Mar	0.0109
Apr	0.0103
May	0.0131
Jun	0.0225
Jul	0.0249
Aug	0.0198
Sep	0.0240
Oct	0.0191
Nov	0.0123
Dec	0.0118

Thank you,

Joe

Joseph D. Adams
SPU Planning & Engineering Director
jadams@shakopeeutilities.com
952-233-1501

Adams, Joe

To: Fenstermacher, Christian
Subject: RE: DER Tariff Questions

From: Fenstermacher, Christian
Sent: Thursday, May 2, 2019 4:50 PM
To: Adams, Joe <jadams@shakopeeutilities.com>
Subject: DER Tariff Questions

Joe,

Besides the net meter customers that have asked questions via email, I have talked to DER Customer 4 (via a phone call) and DER Customer 5 (in person).

DER Customer 4 - Phone call. He simply asked how it was calculated now and how it will be calculated going forward. He did not have any concerns after I explained the new rate versus the previous credit calculations. He is aware that there is a slight difference in that the RUG and CPC will no longer be included in the credit calculation.

DER Customer 5 – He came into our front office and asked for me so I answered his questions in person. He was actually surprised that we have been paying him for the excess energy at the retail rate with the seasonal PCA and riders included. He genuinely stated that this was not right and we shouldn't pay him at retail since we would be losing money. He thought we should be paying him at our wholesale rates. I informed him that in fact the state statute required utilities to offer the Average Utility Retail rate for all net metering arrangements but that it is capped at 40kW or less per interconnection. He had no concerns about the change to the Average Utility Retail Rate.

Christian Fenstermacher, PE
Project Engineer
Shakopee Public Utilities - Planning & Engineering
PO Box 470; 255 Sarazin Street; Shakopee, MN 55379
Phone: 952-345-2475

RESOLUTION #1245

A RESOLUTION APPROVING SHAKOPEE PUBLIC UTILITIES COMMISSION'S COGENERATION AND SMALL POWER PRODUCTION TARIFF

WHEREAS, the Rules Governing the Interconnection of Cogeneration and Small Power Production Facilities with Shakopee Public Utilities Commission and Minnesota Statutes Section 216B.164 require the utility to annually adopt a Cogeneration and Small Power Production Tariff.

WHEREAS, Schedule 1 shall contain the calculation of the average retail utility rates to be updated annually.

WHEREAS, Schedule 2 shall contain all standard contracts to be used with qualifying facilities, containing applicable terms and conditions.

WHEREAS, Schedule 3 shall contain the utility's adopted interconnection process, safety standards, technical requirements for distributed energy resource systems, required operating procedures for interconnected operations, and the functions to be performed by any control and protective apparatus.

WHEREAS, Schedule 4 shall contain the estimated average incremental energy costs by seasonal, peak and off-peak periods for the utility's power supplier from which energy purchases are first avoided. Schedule 4 shall also contain the net annual avoided capacity costs, if any, stated per kilowatt-hour and averaged over the on-peak hours and over all hours for the utility's power supplier from which capacity purchases are first avoided. Both the average incremental energy costs and net annual avoided capacity costs shall be increased by a factor equal to 50 percent of the utility and the utility's power supplier's overall line losses due to distribution, transmission and transformation of electric energy.

WHERAS, these filings shall be maintained at the Shakopee Public Utilities Commission offices and shall be made available for public inspection during normal business hours.

THEREFORE, BE IT RESOLVED that the Shakopee Public Utilities Commission approves the following Cogeneration and Small Power Production Tariff effective beginning July 1, 2019 or the nearest regular meter reading date following, and apply to usage/output after that date and to subsequent billing periods.

Adopted in the regular session of the Shakopee Public Utilities Commission, this 6th day of May, 2019.

Commission President: Terrance Joos

SCHEDULE 1 – AVERAGE RETAIL UTILITY ENERGY RATES

Average Retail Utility Energy Rate: Available to any Qualifying Facility of less than 40 kW capacity that does not select either Roll Over Credits, Simultaneous Purchase and Sale Billing or Time of Day rates.

Utility shall bill Qualifying Facilities for any excess of energy supplied by Utility above energy supplied by the Qualifying Facility during each billing period according to Utility's applicable rate schedule. Utility shall pay the customer for the energy generated by the Qualifying Facility that exceeds that supplied by Utility during a billing period at the "average retail utility energy rate." "Average retail utility energy rate" means, for any class of utility customer, the quotient of the total annual class revenue from sales of electricity minus the annual revenue resulting from fixed charges, divided by the annual class kilowatt-hour sales. Data from the most recent 12-month period available shall be used in the computation.

"Average retail utility energy rates" are as follows:

	2018
RESIDENTIAL	
TOTAL REVENUES	$ 17,891,566.43
LESS UNDERGROUND RELOCATION FEES	$ 110,636.06
LESS FIXED REVENUES (CUSTOMER CHARGE)	$ 1,643,595.00
NET REVENUES	$ 16,137,335.37
TOTAL KWH SALES	$ 139,277,526.00
AVERAGE RETAIL ENERGY RATE	**$ 0.1159**
COMMERCIAL	
TOTAL REVENUES	$ 1,648,656.86
LESS WATER DIVISION ELECTRIC FOR PUMPING	$ 265,755.03
LESS FIXED REVENUES (CUSTOMER CHARGE)	$ 182,966.00
NET REVENUES	$ 1,199,935.83
TOTAL KWH SALES	$ 10,453,260.00
AVERAGE RETAIL ENERGY RATE	**$ 0.1148**
INDUSTRIAL	
TOTAL REVENUES	$ 29,766,176.60
LESS FIXED REVENUES (CUSTOMER CHARGE)	$ 462,998.00
LESS DEMAND CHARGES	$ 6,837,050.72
NET REVENUES	$ 22,466,127.88
TOTAL KWH SALES	$ 303,338,391.00
AVERAGE RETAIL ENERGY RATE	**$ 0.0741**

UNIFORM CONTRACT FOR COGENERATION AND SMALL POWER PRODUCTION FACILITIES

THIS CONTRACT is entered into ___________________, ___, by Shakopee Public Utilities Commission, a municipal utility under Minnesota law, (hereafter called "Utility") and _______________________________________ (hereafter called "QF").

RECITALS

The QF has installed electric generating facilities, consisting of __________________ ____________________________ (Description of facilities), rated at ____kilowatts AC of electricity, on property located at ____ ____.

The QF is a customer of the Utility located within the assigned electric service territory of the Utility.

The QF is prepared to generate electricity in parallel with the Utility.

The QF's electric generating facilities meet the requirements of the rules adopted by the Utility on Cogeneration and Small Power Production and any technical standards for interconnection the Utility has established that are authorized by those rules.

The Utility is obligated under federal and Minnesota law to interconnect with the QF and to purchase electricity offered for sale by the QF.

A contract between the QF and the Utility is required.

AGREEMENTS

The QF and the Utility agree:

1. The Utility will sell electricity to the QF under the rate schedule in force for the class of customer to which the QF belongs.

2. The Utility will buy electricity from the QF under the current rate schedule filed with the city council or city-appointed governing body of the utility. The QF elects the rate schedule category hereinafter indicated:

____ a. Average retail utility energy rate.

- QF capacity must be less than 40 kW.

____ b. Simultaneous purchase and sale billing rate.

- QF capacity must be less than 40 kW.

____ c. Roll-over credits.

- QF capacity must be less than 40 kW.

____ d. Time-of-day purchase rates.

- QF capacity must be 40 kW or more and less than or equal to 100 kW.

A copy of the presently approved rate schedule is attached to this contract.

3. The rates for sales and purchases of electricity may change over the time this contract is in force, due to actions of the Utility or the State of Minnesota, and the QF and the Utility agree that sales and purchases will be made under the rates in effect each month during the time this contract is in force.

4. The Utility will compute the charges and payments for purchases and sales for each billing period. Any net credit to the QF, other than kilowatt-hour credits under clause 2(c), will be made under one of the following options as chosen by the QF.

____ a. Credit to the QF's account with the Utility.

____ b. Paid by check or electronic payment service to the QF within fifteen (15) days of the billing date.

5. Renewable energy credits associated with generation from the facility are owned by:

____.

6. The QF must operate its electric generating facilities within any rules, regulations, and policies adopted by the Utility not prohibited by the rules governing Cogeneration and Small Power Production on the Utility's system which provide reasonable technical connection and operating specifications for the QF and are consistent with the Minnesota Public Utilities Commission's rules on Cogeneration and Small Power Production, as required under Minnesota Statutes §216B.164, subdivision 9.

7. The QF will not enter into an arrangement whereby electricity from the generating facilities will be sold to an end user in violation of the Utility's exclusive right to provide electric service in its service area under Minnesota Statutes, §216B.37-44.

8. The QF will operate its electric generating facilities so that they conform to the national, state, and local electric and safety codes, and will be responsible for the costs of conformance.

9. The QF is responsible for the actual, reasonable costs of interconnection which are estimated to be $__________. The QF will pay the Utility in this way:

____

____.

10. The QF will give the Utility reasonable access to its property and electric generating facilities if the configuration of those facilities does not permit disconnection or testing from the Utility 's side of the interconnection. If the Utility enters the QF's property, the Utility will remain responsible for its personnel.

11. The Utility may stop providing electricity to the QF during a system emergency. The Utility will not discriminate against the QF when it stops providing electricity or when it resumes providing electricity.

12. The Utility may stop purchasing electricity from the QF when necessary for the Utility to construct, install, maintain, repair, replace, remove, investigate, or inspect any equipment or facilities within its electric system. The Utility may stop purchasing electricity from the QF in the event the generating facilities listed in this contract are documented to be causing power quality, safety or reliability issues to the Utility's electric distribution system.

    The Utility will notify the QF before it stops purchasing electricity in this way:

    ____

    ____.

13. The QF will keep in force general liability insurance against personal or property damage due to the installation, interconnection, and operation of its electric generating facilities. The amount of insurance coverage will be $ __________. (The amount must be consistent with the distributed generation tariff adopted by the Utility pursuant to Minnesota Statutes §216B.1611, subdivision 3, clause 2.)

14. The QF and the Utility agree to attempt to resolve all disputes arising hereunder promptly and in a good faith manner.

15. The city council or city-appointed body governing the Utility has authority to consider and determine disputes, if any, that arise under this contract in accordance with procedures in the rules it adopts implementing Minnesota Statute §216B.164, pursuant to §216B.164, subdivision 9.

16. This contract becomes effective as soon as it is signed by the QF and the Utility. This contract will remain in force until either the QF or the Utility gives written notice to the other that the contract is canceled. This contract will be canceled thirty (30) days after notice is given. If the listed electric generating facilities are not

interconnected to the Utility's distribution system within twelve months of the contract being signed by the QF and the Utility, the contract terminates. The QF and the Utility may delay termination by mutual agreement.

17. Neither the QF nor the Utility will be considered in default as to any obligation if the QF or the Utility is prevented from fulfilling the obligation due to an act of God, labor disturbance, act of public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, an order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities, or other cause beyond the QF's or Utility's control. However, the QF or Utility whose performance under this contract is hindered by such an event shall make all reasonable efforts to perform its obligations.

18. This contract can only be amended or modified by mutual agreement in writing signed by the QF and the Utility.

19. The QF must notify the Utility prior to any change in the electric generating facilities' capacity size or generating technology according to the interconnection process adopted by the Utility.

20. Termination of this contract is allowed (i) by the QF at any time without restriction; (ii) by Mutual Agreement between the Utility and the QF; (iii) upon abandonment or removal of electric generating facilities by the QF; (iv) by the Utility if the electric generating facilities are continuously non-operational for any twelve (12) consecutive month period; (v) by the Utility if the QF fails to comply with applicable interconnection design requirements or fails to remedy a violation of the interconnection process; or (vi) by the Utility upon breach of this contract by the QF unless cured with notice of cure received by the Utility prior to termination.

21. In the event this contract is terminated, the Utility shall have the rights to disconnect its facilities or direct the QF to disconnect its generating facilities.

22. This contract shall continue in effect after termination to the extent necessary to allow either the Utility or the QF to fulfill rights or obligations that arose under the contract.

23. Transfer of ownership of the generating facilities shall require the new owners and the Utility to execute a new contract. Upon the execution of a new contract with the new owners this contract shall be terminated.

24. The QF and the Utility shall at all times indemnify, defend, and save each other harmless from any and all damages, losses, claims, including claims and actions relating to injury or death of any person or damage to property, costs and expenses, reasonable attorneys' fees and court costs, arising out of or resulting from the QF's or the Utility's performance of its obligations under this contract,

except to the extent that such damages, losses or claims were caused by the negligence or intentional acts of the QF or the Utility.

25. The Utility and the QF will each be responsible for its own acts or omissions and the results thereof to the extent authorized by law and shall not be responsible for the acts or omissions of any others and the results thereof.

26. The QF's and the Utility's liability to each other for failure to perform its obligations under this contract shall be limited to the amount of direct damage actually occurred. In no event, shall the QF or the Utility be liable to each other for any punitive, incidental, indirect, special, or consequential damages of any kind whatsoever, including for loss of business opportunity or profits, regardless of whether such damages were foreseen.

27. The Utility does not give any warranty, expressed or implied, to the adequacy, safety, or other characteristics of the QF's interconnected system.

28. This contract contains all the agreements made between the QF and the Utility. The QF and Utility are not responsible other than those stated in this contract.

THE QF AND THE UTILITY HAVE READ THIS CONTRACT AND AGREE TO BE BOUND BY ITS TERMS. AS EVIDENCE OF THEIR AGREEMENT, THEY HAVE EACH SIGNED THIS CONTRACT BELOW ON THE DATE LISTED BY SIGNER.

QF

By: ______________________________

Printed Name:______________________

DATE: ___________________________

UTILITY

By: ______________________________

Printed Name:______________________

DATE: ___________________________

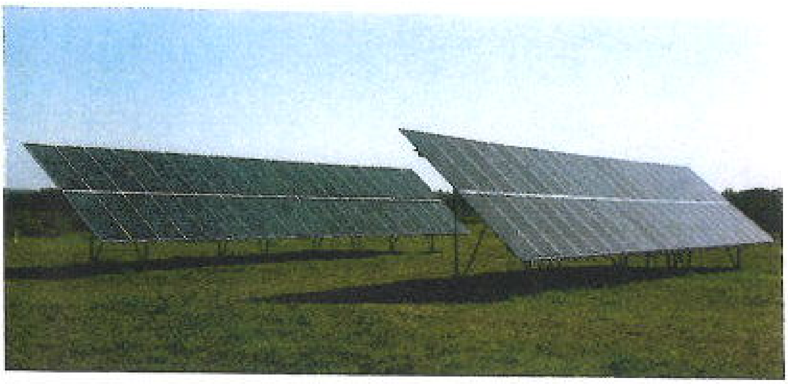
Contract Version: *February 2019*

SHAKOPEE PUBLIC UTILITIES
"Lighting the Way – Yesterday, Today and Beyond"

SHAKOPEE PUBLIC UTILITIES COMMISSION

DISTRIBUTED ENERGY RESOURCE INTERCONNECTION PROCESS

Table of Contents



Detroit Lakes Public Utility's 29.3 KW Select Solar Community Solar Garden Detroit Lakes, MN

INTERCONNECTION PROCESS

Process Overview

ABSTRACT

Interconnection Process for Distributed Energy Resources less than 10 megawatt (MW) interconnected to the Distribution System of a Municipal in the State of Minnesota.

Contents

Foreword

The State of Minnesota currently has interconnection process standards in effect to address the interconnection of distributed energy resources (DER) to the distribution grid. Under Minnesota Statute §216B.1611, cooperatives and municipals shall adopt an interconnection process that addresses the same issues as the interconnection process approved by the Minnesota Public Utilities Commission. The Municipal Minnesota Distributed Energy Resources Interconnection Process (Interconnection Process or M-MIP) applies to any DER no larger than 10-megawatt (MW) AC interconnecting to and operating in parallel with Shakopee Public Utilities Commission's distribution system in Minnesota. This interconnection process document is designed to be customer-centric when explaining the steps and details to interconnect DER systems to the distribution grid.

The interconnection process document is broken into five parts: Process Overview, Simplified Process, Fast Track Process, Study Process and Interconnection Agreement. For the majority of DER interconnection, only the Process Overview and the Simplified Process parts will apply. For larger and more complex DER interconnections, the Fast Track Process and the Study Process may apply.

In addition to the interconnection process documents, interconnection agreement(s) are to be executed prior to the DER system being interconnected to the distribution grid. For most DER interconnection, the Shakopee Public Utilities Commission Contract for Cogeneration and Small Power Production Facilities (Uniform Contract) will be used. For DER systems that do not fall under the terms of the Uniform Contract, the M-MIP Interconnection Agreement will apply.

The process to interconnect a DER system to the distribution grid starts with the submission of an Interconnection Application. Each track has different information that is requested in the application and the non-refundable interconnection application fees will vary. Both the electric utility and the interconnecting customer have timelines that are enforced to ensure a timely application review, contract execution and interconnection commissioning.

The key to a successful interconnection of a DER system is communication between all parties. Timely submission of the Interconnection Application prior to the purchase and installation of a DER system is strongly recommended. The Utility encourages customers to ask questions throughout the interconnection process. Interconnecting DER system to the distribution grid is not an effortless process, but it does not need to be a problematic process either.

1 Key Terminology

1.1. Distributed Energy Resource

Distributed Energy Resources, DER, was often referred to in past interconnection processes as Distributed Generation, DG, and on occasion also interchanged with the term Qualifying Facility, QF. This Interconnection Process uses the term DER to address all types of generation and energy resources that can be interconnected to the electric distribution system. DER technologies can include photovoltaic solar systems, wind turbines, storage batteries or diesel generators and are not limited to renewable types of technologies.

1.2. Point of Coupling/Connection

DER systems often reside behind the utility's revenue meter of a residence or business. The meter is normally the point of demarcation between the utility-owned equipment and the customer-owned equipment. The term Point of Common Coupling, PCC, is the demarcation location between the utility and the customer.

The Point of DER Connection, PoC, can be different from the PCC. The PoC is the location where a DER system(s) would interconnect to the electrical system normally owned by the customer. For example, the PoC for a rooftop photovoltaic solar system may the main electrical panel in a customer's home.

1.3. Capacity

Throughout the Interconnection Process will be references to capacity of the DER system. In most cases, the capacity listed is referring to the Nameplate Capacity of the DER system. All capacity reference will be in alternating current, AC.

There can be multiple DER systems with different PoCs that all have the same PCC submitted on a single interconnection application. The capacity for this type of interconnection would be the aggregate Nameplate Capacity of all DER systems at the individual PoCs. Additional examples of DER system arrangements can be seen in Section 13 under the definition of Point of Common Coupling.

2 Roles

2.1. Overview

During the interconnection process for a proposed DER system, there are multiple entities involved in the application, approval and commissioning processes. The main entities that are involved during the Interconnection Process for a proposed DER system are the Interconnection Customer, the Application Agent and the DER

Interconnection Coordinator. Official definitions of each entity are defined in the Glossary (Section 13). Additional details are explained in the subsections below.

2.2. DER Interconnection Coordinator

The utility is referred to as the Area Electric Power Supply Operator in this Interconnection Process. The Area EPS Operator shall designate a DER Interconnection Coordinator(s) to serve as a single point of contact from which general information on the application process may be obtained. The DER Interconnection Coordinator shall be available to provide coordination assistance with the Interconnection Customer but is not responsible to directly answer or resolve all of the issues involved in review and implementation of the interconnection process and standards.

The contact information of the DER Interconnection Coordinator will be posted on the Area EPS Operator's website when feasible.

2.3. Interconnection Customer

The owner of the proposed DER system and the entity requesting interconnection to the distribution system.

2.4. Application Agent

The Interconnection Customer may designate, on the Interconnection Application or in writing after the application has been submitted, an Application Agent to serve as a single point of contact to coordinate with the DER Interconnection Coordinator on their behalf. Designation of an Application Agent does not absolve the Interconnection Customer from signing application documents and the responsibilities outlined in the Interconnection Process or in interconnection agreements. DER vendors, project managers or electricians are common entities that the Interconnection Customer may designate to perform this role.

2.5. Engineering Roles

Either party may designate a specific person to be a single point of contact to provide technical expertise during the Interconnection Process for their organization. The person to supply engineering expertise may be a third party such as an engineering consultant or manufacturer's engineer.

3 Processes

3.1. Overview

The Interconnection Process applies to any DER no larger than 10 MW AC interconnecting to and operating in parallel with an Area EPS distribution system in

Minnesota. Interested parties with plans to interconnect DER systems larger than 10 MW AC to the distribution system should contact the Area EPS Operator for the specific interconnection process. Federal Energy Regulatory Commission's (FERC) interconnection process will supersede any interconnection process the Area EPS Operator has for DER system interconnections that fall under the jurisdiction of FERC.

The Interconnection Process for DER is broken into three different tracks; the Simplified Process, the Fast Track Process, and the Study Process. The general classification of each track is summarized in Table 3.1 below.

Table 3.1. Interconnection Process Tracks

Track	DER Technology	Size Limitations
Simplified Process	Certified Inverter only	20 kW AC
Fast Track Process	All types	5 MW AC
Study Process	All types	10 MW AC

If engineering screens are failed during the application process, a proposed DER interconnection may be moved into a different track. When a proposed DER interconnection is moved into a different track, additional information may be requested and additional fees may apply.

3.2. Importance of Process Timelines

It is very important to pay attention to timelines listed for each process track. The timelines exist for an orderly and efficient process to interconnect DER systems to the Distribution System. If a timeline is missed by an Interconnection Customer, without the Interconnection Customer requesting a Timeline Extension explained in Section 10, the Interconnection Application will be deem withdrawn by the Area EPS Operator.

The Area EPS Operator also need to abided to the timelines listed for each process track. The process for an Area EPS Operator to request Timeline Extensions is also addressed in Section 10.

Unless otherwise state, all time frames are measured in Business Days. For purpose of measuring these time intervals, the time shall be computed so as to exclude the first and include the last day of the prescribed duration of time. Any communication sent or received after 4:30 p.m. Central Prevailing Time or on a Saturday, Sunday or Holiday shall be considered to be sent on the next Business Day.

3.3. Simplified Process

An application to interconnect a certified[1], inverter-based DER system no larger than 20 kilowatts (kW) shall be evaluated under the Simplified Process. A common form of DER inverter certification is UL 1741. Proposed DER systems that require Area EPS system modifications to accommodate the interconnection do not qualify for the Simplified Process. A transformer change, fusing upgrades or line extensions are common examples of Area EPS system modification. Simplified Process eligibility does not imply or indicate the Interconnection Application will pass the initial review screens. Failure to pass the screens will route the Interconnection Application to the Fast Track Process.

3.4. Fast Track Process

An application to interconnect a DER shall be evaluated under the Fast Track Process if the eligibility requirements are not exceeded in Table 3.2 and the application does not qualify for the Simplified Process. Fast Track eligibility for DERs is determined based upon the generator type, the size of the generator, voltage of the line, and the location of and the type of line at the Point of Common Coupling, (PCC). All synchronous and induction machines must be no larger than 2 MW to be eligible for Fast Track Process consideration.

Table 3.2. Fast Track Eligibility for DER

Line Voltage	Fast Track Eligibility[2] Regardless of Location	Fast Track Eligibility for certified, inverter-based DER on a Mainline[3] and ≤ 2.5 Electrical Circuit Miles from Substation[4]
< 5 kV	≤ 500 kW	≤ 500 kW
≥ 5 kV and < 15 kV	≤ 1 MW	≤ 2 MW
≥ 15 kV and < 30 kV	≤ 2 MW	≤ 4 MW
≥ 30 kV and ≤ 69 kV	≤ 4 MW	≤ 5 MW

In addition to the size threshold, the Interconnection Customer's proposed DER must meet the codes, standards and certification requirements found in Section 15 and Section 14.

---

[1] Additional information regarding certified equipment is found in Section 15 and Section 14.

[2] Synchronous and induction machine eligibility is limited to no more than 2 MW even when line voltage is greater than 15 kV.

[3] For purposes of this table, a Mainline is the three-phase backbone of a circuit. It will typically constitute lines with wire sizes of 4/0 American wire gauge, 266 kcmil, 336.4 kcmil, 397.5 kcmil, 477 kcmil and 795 kcmil.

[4] An Interconnection Customer can determine this information about its proposed interconnection location in advance by requesting a pre-application report described in Section 5.

3.5. Study Process

An application to interconnect a DER that does not meet the Simplified Process or Fast Track Process eligibility requirements or does not pass the review as described in either process, shall be evaluated under the Study Process.

3.6. Process Assistance

Prior to submitting an Interconnection Application, the Interconnection Customer may ask the Area EPS Operator's DER Interconnection Coordinator which process track a proposed interconnection is subject to and additional details on each process track.

An Interconnection Customer can obtain, through an informal request, general information about the interconnection process and on Affected System(s) for a proposed interconnection at a specific location. Upon request, the existing electric system information provided to the Interconnection Customer should include relevant system study results, interconnection studies, and other materials useful to an understanding of an interconnection at a particular point on the Area EPS Operator's System. Information will be provided to the extent such provision does not violate the privacy policies of the Area EPS Operator, confidentiality provisions of prior agreements or critical infrastructure requirements. The Area EPS Operator shall comply with reasonable requests for such information.

4 Interconnection Application

4.1. Overview

Each process track has different information that needs to be provided to the Area EPS Operator. Table 4.1 indicates which application is to be completed in its entirety and submitted to the Area EPS Operator to start the interconnection process for the proposed DER system.

Table 4.1. Interconnection Application

Process Track	Application
Simplified	Simplified Interconnection Application
Fast Track	Standard Interconnection Application
Study	Standard Interconnection Application

The Area EPS Operator will provide all necessary Interconnection Applications, Interconnection Process documents and sample interconnection agreements on its website if possible. The Area EPS Operator will also accept Interconnection Applications submitted electronically either through a web portal or to an email address specified by the Area EPS Operator. The Area EPS Operator may allow the Interconnection Application to be submitted with an electronic signature.

4.2. Availability of Information

The Area EPS Operator will provide all necessary Interconnection Applications, Interconnection Process documents and sample interconnection agreements on its website if possible. If a website is not available, the applicable documents will be readily available at the Area EPS Operator's main office.

The Area EPS Operator will establish a public queue of active interconnection applications on its website once the Area EPS Operator has received at least 40 completed Interconnection Applications in a year. The public queue will be updated, at minimum, on a monthly basis.

4.3. Interconnection Application Process Fees

Each Interconnection Application submitted to the Area EPS Operator must include the appropriate interconnection application process fee prior to the Area EPS Operator reviewing the Interconnection Application. The required process fee for each process track is listed in Table 4.2.

Table 4.2. Interconnection Application Process Fee

Process Track		Process Fee
Simplified		$100
Fast Track	Certified[5] System	$100 + $1/kW
	Non-Certified System	$100 + $2/kW
Study		$1,000 + $2/kW down payment. Additional study fees may apply.

4.4. Application Review Timelines

The Interconnection Application shall be date- and time-stamped upon initial, and if necessary, resubmission receipt. The Area EPS Operator shall notify the Interconnection Customer if the Interconnection Application is deemed incomplete within ten (10) Business Days. This notification shall include a written list detailing all information that must be provided to complete the Interconnection Application. Depending on the process track the Interconnection Customer has between five (5) and ten (10) Business Days to provide the missing information unless additional time is

[5] Additional information regarding certified equipment is found in Section 15 and Section 14.

requested with valid reasons. Failure to submit the requested information within the stated timeline will result in the Interconnection Application being withdrawn.

An Interconnection Application will be deemed complete upon submission to the Area EPS Operator when all documents, fees and information required with the Interconnection Application adhering to Minnesota Technical Requirements is included. The time- and date- stamp of the completed Interconnection Application shall be accepted as the qualifying date for purposes of establishing a queue position as described in Section 4.7.

Depending on the process track the Area EPS Operator has either a total of twenty (20) Business Days or twenty-five (25) Business Days to complete the Interconnection Application review and submit notice back to the Interconnection Customer stating the proposed DER system may proceed with the interconnection process or the proposed DER system requires additional engineering studies. The period of time when waiting for the Interconnection Customer to provide missing information is not included in the Area EPS Operator's twenty (20) Business Days or twenty-five (25) Business Days review timeline.

4.5. Comparability

The Area EPS Operator shall receive, process and analyze all Interconnection Applications in a timely manner. The Area EPS Operator shall use the same Reasonable Efforts in processing and analyzing Interconnection Applications from all Interconnection Customers.

4.6. Changing Process Queues

During the review of the initially submitted Interconnection Application for the proposed DER system, the Area EPS Operator may determine the proposed DER system should be in a different process track. For proposed DER systems that are moved into a different process track after submittal of the initial application, the difference between the originally submitted processing fee and the current process track's processing fee will be assessed. In addition, the Area EPS Operator may request the Interconnection Customer to provide additional information regarding the proposed DER system.

4.7. Queue Position

The Area EPS Operator shall maintain a single, administrative queue and may manage the queue by geographical region. The queue position of each completed Interconnection Application is used to determine the engineering review. The queue position is also used to determine the cost responsibility for system upgrades necessary to accommodate the interconnection.

An Interconnection Application will retain its queue number even when it is moved into a different process track. An Interconnection Application can lose its queue position if the Interconnection Customer misses timelines in the applicable process track. The Interconnection Customer and Area EPS Operator have the opportunity to request timeline extensions which are explained in detail in Section 10.

4.8. Site Control

Documentation of site control must be submitted with the Interconnection Application. Site control may be demonstrated by any of the following:

- Ownership of, a leasehold interest in, or a right to develop a site for the purpose of constructing the DER system.

- An option to purchase or acquire a leasehold site for constructing the DER system.

- An exclusivity or other business relationship between the Interconnection Customer and the entity having the right to sell, lease, or grant the Interconnection Customer the right to possess or occupy a site for constructing the DER system.

For DER in the Simplified Process, proof of site control may be demonstrated by the site owner's signature on the Simplified Interconnection Application.

5 Pre-Application Report

5.1. Pre-Application Report Requests

The Interconnection Customer may submit a Pre-Application Report Request, including a non-refundable fee of $300, for a Pre-Application Report on a proposed project at a specific site. The Interconnection Customer must fill out the Pre-Application Request form as completely as possible. The Area EPS Operator shall provide the readily available data listed in Section 5.3 within fifteen (15) Business Days of receipt of a completed request form and payment. The Pre-Application Report produced by the Area EPS Operator is non-binding, does not confer any rights, and does not preclude the Interconnection Customer from any interconnection process steps including submission of the Interconnection Application.

5.2. Information Provided

Using the information provided in the Pre-Application Report Request form, the Area EPS Operator will identify the substation/area bus, bank or circuit likely to serve the proposed PCC. This selection by the Area EPS Operator does not necessarily indicate, after application of the screens and/or study, that this would be the circuit the project ultimately connects to. The Interconnection Customer must request additional Pre-Application Reports if information about multiple PCC is requested.

The Pre-Application Report will only include existing data. A request for a Pre-Application Report does not obligate the Area EPS Operator to conduct a study or other analysis of the proposed DER in the event that data is not readily available. The Area EPS Operator will provide the Interconnection Customer with the data that is available. The confidentiality provisions in Section 12.1 **Error! Reference source not found.**apply to Pre-Application Reports.

5.3. Pre-Application Report Components

The Pre-Application Report shall include following pieces of information provided the data currently exists and is readily available.

- Total capacity (in megawatts (MW)) of substation/area bus, bank or circuit based on normal or operating ratings likely to serve the proposed Point of Common Coupling.
- Existing aggregate generation capacity (in MW) interconnected to a substation/area bus, bank or circuit (i.e., amount of generation online) likely to serve the proposed Point of Common Coupling.
- Aggregate queued generation capacity (in MW) for a substation/area bus, bank or circuit (i.e., amount of generation in the queue) likely to serve the proposed Point of Common Coupling.
- Available capacity (in MW) of substation/area bus or bank and circuit likely to serve the proposed Point of Common Coupling (i.e., total capacity less the sum of existing aggregate generation capacity and aggregate queued generation capacity).
- Substation nominal distribution voltage and/or transmission nominal voltage if applicable.
- Nominal distribution circuit voltage at the proposed Point of Common Coupling.
- Approximate circuit distance between the proposed Point of Common Coupling and the substation.
- Relevant line section(s) actual or estimated peak load and minimum load data, including daytime minimum load and absolute minimum load, when available.

- Whether the Point of Common Coupling is located behind a line voltage regulator.
- Number and rating of protective devices and number and type (standard, bi-directional) of voltage regulating devices between the proposed Point of Common Coupling and the substation/area. Identify whether the substation has a load tap changer.
- Number of phases available on the Area EPS medium voltage system at the proposed Point of Common Coupling. If a single phase, distance from the three-phase circuit.
- Limiting conductor ratings from the proposed Point of Common Coupling to the distribution substation.
- Whether the Point of Common Coupling is located on a spot network, grid network, or radial supply.
- Based on the proposed Point of Common Coupling, existing or known constraints such as, but not limited to, electrical dependencies at that location, short circuit interrupting capacity issues, power quality or stability issues on the circuit, capacity constraints, or secondary networks

6 Capacity of the Distributed Energy Resources

6.1. Existing DER System Expansion

If the Interconnection Application is for an increase in capacity to an existing DER system, the Interconnection Application shall be evaluated on the basis on the total new alternating current (AC) capacity of the DER. The maximum capacity for the DER shall be the aggregate maximum Nameplate Rating unless the conditions in Section 6.3 are met.

6.2. New DER Systems

An Interconnection Application for a DER that includes a single or multiple energy production devices, (i.e. solar and storage), at a site for which the Interconnection Customer seeks a simple Point of Coupling, shall be evaluated on the basis of the aggregated maximum Nameplate Rating unless the conditions in Section 6.3 are met.

6.3. Limited Capacity

A DER system may include devices, (i.e. control systems, power relays or other similar device settings), that can limit the maximum capacity at which the DER system can generate into the Area EPS Operator's distribution system. For DER system that include capacity limited devices, the Interconnection Customer must obtain the Area EPS

Operator's agreement to consider the DER system with the Nameplate Rating as the limited capacity. The Area EPS Operator's agreement shall not be unreasonable withheld provided proper documentation is provided showing the effective limit active power output will not adversely affect the safety and reliability of the Area EPS Operator's distribution system. If the Area EPS Operator does not agree, the Interconnection Application must be withdrawn or revised to specify the maximum capacity that the DER system is capable of injecting into the Area EPS Operator's distribution system without such limitations. Nothing in this section shall prevent the Area EPS Operator from considering a higher output, (i.e. aggregate Nameplate Rating), if the limitations do not provide adequate assurance, when evaluating the system impacts.

7 Modification to Interconnection Applications

7.1. Procedures

At any time after the Interconnection Application is deemed complete, the Interconnection Customer or the Area EPS Operator may identify modifications to the proposed DER system that may improve costs and benefits (including reliability) of the proposed DER system and the ability for the Area EPS Operator to accommodate the proposed DER system. The Interconnection Customer shall submit to the Area EPS Operator in writing all proposed modifications to any information provided in the Interconnection Application. The Area EPS Operator cannot unilaterally modify the Interconnection Application.

Additional information regarding modifications to interconnection applications is found in each process track document.

8 Interconnection Agreements

8.1. Timelines

After the Interconnection Application has been approved by the Area EPS Operator, the Area EPS Operator shall provide the Interconnection Customer with an executable Interconnection Agreement within five (5) Business Days. The Interconnection Customer shall have thirty (30) Business Days to sign and return the Interconnection Agreement to the Area EPS Operator. The Area EPS Operator shall sign the Interconnection Agreement within five (5) business days after receiving the signed Interconnection Agreement from the Interconnection Customer.

If the Interconnection Customer fails to return a signed Interconnection Agreement to the Area EPS Operator within thirty (30) Business Days and fails to request an extension as explained in Section 10, the Interconnection Application will be deemed withdrawn.

8.2. Types of Agreements

There are two main types of Interconnection Agreements that may be executed with an approved Interconnection Application. In general, Interconnection Customers with a proposed DER system that qualifies for the Simplified Process track will sign the Area EPS Operator's Uniform Contract for Cogeneration and Small Power Production Facilities (Uniform Contract). Proposed DER systems less than 100 kW that are under the Fast Track process may also sign the Uniform Contract. All other sized DER system will sign the Interconnection Agreement. Area EPS Operators who do not purchase the excess generation of the proposed DER system will also require the Interconnection Agreement executed for any size of DER system.

Table 8.1. Interconnection Agreements

<table>
<tr><th colspan="2">Process Track</th><th>Interconnection Agreement</th></tr>
<tr><td colspan="2">Simplified</td><td>Uniform Contract</td></tr>
<tr><td rowspan="3">Fast Track</td><td>Qualifies for Net Energy Billing</td><td>Uniform Contract</td></tr>
<tr><td>Less than 100 kW & Area EPS Agrees to Purchase Excess Generation</td><td>Uniform Contract</td></tr>
<tr><td>All Other DER systems</td><td>Interconnection Agreement</td></tr>
<tr><td colspan="2">Study</td><td>Interconnection Agreement</td></tr>
</table>

Interconnection Customers may choose to sign the Interconnection Agreement in lieu of the Uniform Contact. A separate power purchase agreement will also need to be executed if the Uniform Contract is not utilized. Interconnection of the proposed DER system will not occur until a signed Uniform Contract or the Interconnection Agreement is returned to the Area EPS Operator no later than five (5) days prior to schedule testing and inspection.

9 Interconnection

9.1. Metering

Any metering requirements necessitated by the use of the DER system shall be installed at the Interconnection Customer's expense. The metering requirement costs will be included in the final invoice of interconnection costs to the Interconnection Customer. The Interconnection Customer is also responsible for metering replacement costs not covered in the Interconnection Customer's general customer charge. The Area EPS Operator may charge Interconnection Customers an ongoing metering-related charge for an estimate of ongoing metering-related costs specifically demonstrated.

9.2. Inspection, Testing and Commissioning

The Interconnection Customer shall arrange for the inspection and testing of the DER system and the Customer's Interconnection Facilities prior to interconnection pursuant to Minnesota Interconnection Technical Requirements. Commissioning tests of the Interconnection Customer's installed equipment shall be performed pursuant to applicable codes and standards of Minnesota's Technical Requirements and Section 15.

The Interconnection Customer shall notify the Area EPS Operator of testing and inspection no fewer than five (5) Business Days in advance, or as may be agreed to by the Parties. Depending on the process track, either a Certificate of Completion or a testing procedure shall be submitted to the Area EPS Operator prior to the testing and inspection date. The Area EPS Operator shall send qualified personnel to the DER site to inspect the interconnection and witness the testing. Testing and inspection shall occur on a Business Day at a mutually agreed upon time and date. The Area EPS Operator may waive the right to witness the testing.

9.3. Interconnection Costs

The Interconnection Customer shall pay for the actual cost of the Interconnection Facilities and Distribution Upgrades along with the Area EPS Operator's cost to commission the proposed DER system. An estimate of the interconnection costs shall be stated in the Uniform Contract or Interconnection Agreement.

9.4. Non-Warrantee

Area EPS Operator does not give any warranty, expressed or implied, as to the adequacy, safety, or other characteristics of any structures, equipment, wires, appliances or devices owned, operated, installed or maintained by the Interconnection Customer, including without limitation the DER and any structures, equipment, wires, appliances or devices not owned, operated or maintained by the Area EPS Operator. The Area EPS Operator does not guarantee uninterrupted power supply to the DER and will operate the distribution system with the same reliability standards for the entire customer base.

9.5. Technical Requirements

The Area EPS Operator shall use Reasonable Efforts to provide the Interconnection Customer the Minnesota Technical Requirements by providing the document with the notice of approval of the interconnection application or by providing a website link to the document. Additionally, the Area EPS Operator shall notify the Interconnection Customer of any changes to these requirements as soon as they are known. Unless notified by the Area EPS Operator, the Interconnection Customer only needs to be in compliance of the current version of the Minnesota Technical Requirements at the time of interconnection.

9.6. Authorization for Parallel Operations

The Interconnection Customer shall not operate its DER system in parallel with the Area EPS Operator's distribution system without prior written authorization from the Area EPS Operator. The Area EPS Operator shall provide such authorization within three (3) Business Days from when the Area EPS Operator receives notification that the Interconnection Customer has complied with all applicable parallel operations requirements; the completion of a successful testing and inspection of the DER system and all payments for issued bills related to the interconnection process that are past due have been paid in full. Such authorization shall not be unreasonably withheld, conditioned or delayed.

10 Extension of Timelines

10.1. Reasonable Efforts

The Area EPS Operator shall make Reasonable Efforts to meet all time frames provided in these procedures. If the Area EPS Operator cannot meet a deadline provided herein, it must notify the Interconnection Customer in writing within three (3) Business Days after the deadline to explain the reason for the failure to meet the deadline and provide an estimated time by which it will complete the applicable interconnection procedure in the process.

10.2. Extensions

For applicable time frames described in these procedures, the Interconnection Customer may request, in writing, one extension equivalent to half of the time originally allotted (e.g., ten (10) Business Days for a twenty (20) Business Days original time frame) which the Area EPS Operator may not unreasonably refuse. No further extensions for the applicable time frame shall be granted absent a Force Majeure Event or other similarly extraordinary circumstance.

11 Disputes

11.1. Procedures

The Parties agree in a good faith effort to attempt to resolve all disputes arising out of the interconnection process and associated study and Interconnection Agreements. The Parties agree to follow the established dispute resolution policy adopted by the Area EPS Operator.

12 Clauses

12.1. Confidentiality

Confidential Information shall mean any confidential and/or proprietary information provided by one Party to the other Party that is clearly marked or otherwise designated "Confidential." For purposes of these procedures, design, operating specifications, and metering data provided by the Interconnection Customer may be deemed Confidential Information regardless of whether it is clearly marked or otherwise designated as such. If requested by either Party, the other Party shall provide in writing the basis for asserting that the information warrants confidential treatment. Parties providing a Governmental Authority trade secret, privileged or otherwise not public or nonpublic data under Minnesota Government Data Practices Act, Minnesota Statute Chapter 13, shall identify such data consistent with the Commission's September 1, 1999 Revised Procedures for Handling Trade Secret and Privileged Data available online at: https://mn.gov/puc/puc-documents/#4.

Confidential Information does not include information previously in the public domain with proper authorization, required to be publicly submitted or divulged by Governmental Authorities (after notice to the other Party and after exhausting any opportunity to oppose such publication or release), or necessary to be publicly divulged in an action to enforce these procedures. Each Party receiving Confidential Information shall hold such information in confidence and shall not disclose it to any third party nor to the public without the prior written authorization from the Party providing that information, except to fulfill obligations under these procedures, or to fulfill legal or regulatory requirements that could not otherwise be fulfilled by not making the information public.

Each Party shall hold in confidence and shall not disclose Confidential Information, to any person (except employees, officers, representatives and agents, who agree to be bound by this section). Confidential Information shall be clearly marked as such on each page or otherwise affirmatively identified. If a court, government agency or entity with the right, power, and authority to do so, requests or requires either Party, by subpoena, oral disposition, interrogatories, requests for production of documents, administrative order, or otherwise, to disclose Confidential Information, that Party shall provide the other Party with prompt notice of such request(s) or requirements(s) so that the other Party may seek an appropriate protective order or waive compliance with the terms of this Agreement. In the absence of a protective order or waiver the Party shall disclose such confidential information which, in the opinion of its counsel, the party is legally compelled to disclose. Each Party will use reasonable efforts to obtain reliable assurance that confidential treatment will be accorded to any confidential information furnished.

Critical infrastructure information or information that is deemed or otherwise designated by a Party as Critical Energy/Electric Infrastructure Information (CEII) pursuant to FERC regulation, 18 C.F.R. §388.133, as may be amended from time to time, may be subject to further protections for disclosure as required by FERC or FERC regulations or orders and the disclosing Party's CEII policies. Each Party shall employ at least the same standard of care to protect Confidential Information obtained from the other Party as it employs to protect its own Confidential Information.

Confidential Information does not include information previously in the public domain with proper authorization, required to be publicly submitted or divulged by Governmental Authorities (after notice to the other Party and after exhausting any opportunity to oppose such publication or release), or necessary to be publicly divulged in an action to enforce these procedures. Each Party receiving Confidential Information shall hold such information in confidence and shall not disclose it to any third party nor to the public without the prior written authorization from the Party providing that information, except to fulfill obligations under these procedures, or to fulfill legal or regulatory requirements that could not otherwise be fulfilled by not making the information public.

Each Party is entitled to equitable relief, by injunction or otherwise, to enforce its rights under this provision to prevent the release of Confidential Information without bond or proof of damages and may seek other remedies available at law or in equity for breach of this provision.

12.2. Non-Warranty

The Area EPS Operator does not give any warranty, expressed or implied, as to the adequacy, safety, or other characteristics of any structures, equipment, wires, appliances or devices owned, operated, installed or maintained by the Interconnection Customer, including without limitation the DER and any structures, equipment, wires, appliances or devices not owned, operated or maintained by the Area EPS Operator.

12.3. Indemnification

Each Party is protected from liability incurred to third parties as a result of carrying out the provisions of this interconnection process and subsequent interconnection agreements. The Parties shall at all times indemnify, defend, and save the other Party harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the other Party's action or inactions of its obligations under this agreement on behalf of the indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the indemnified Party.

This indemnification obligation shall apply notwithstanding any negligent or intentional acts, errors or omissions of the indemnified Party, but the indemnifying Party's liability to indemnify the indemnified Party shall be reduced in proportion to the percentage by which the indemnified Party's negligent or intentional acts, errors or omissions caused the damages.

Neither Party shall be indemnified for its damages resulting from its sole negligence, intentional acts or willful misconduct. These indemnity provisions shall not be construed to relieve any insurer of its obligation to pay claims consistent with the provisions of a valid insurance policy.

If an indemnified person is entitled to indemnification under this article as a result of a claim by a third party, and the indemnifying Party fails, after notice and reasonable opportunity to proceed under this article, to assume the defense of such claim, such indemnified person may at the expense of the indemnifying Party contest, settle or consent to the entry of any judgment with respect to, or pay in full, such claim.

If an indemnifying party is obligated to indemnify and hold any indemnified person harmless under this article, the amount owing to the indemnified person shall be the amount of such indemnified person's actual loss, net of any insurance or other recovery.

Promptly after receipt by an indemnified person of any claim or notice of the commencement of any action or administrative or legal proceeding or investigation as to which the indemnity provided for in this article may apply, the indemnified person shall notify the indemnifying party of such fact. Any failure of or delay in such notification shall not affect a Party's indemnification obligation unless such failure or delay is materially prejudicial to the indemnifying party.

12.4. Limitation of Liability

Each party's liability to the other party for any loss, cost, claim, injury, liability, or expense, including reasonable attorney's fees, relating to or arising from any act or omission in its performance of this Agreement, shall be limited to the amount of direct damage actually incurred. In no event shall either party be liable to the other party for an indirect, incidental, special, consequential, or punitive damages of any kind whatsoever, except as allowed under in Section 12.3.

13 Glossary

Affected System – Another Area EPS Operator's System, Transmission Owner's Transmission System, or Transmission System connected generation which may be affected by the proposed interconnection.

Applicant Agent – A person designated in writing by the Interconnection Customer to represent or provide information to the Area EPS on the Interconnection Customer's behalf throughout the interconnection process.

Area EPS – The electric power distribution system connected at the Point of Common Coupling.

Area EPS Operator – An entity that owns, controls, or operates the electric power distribution systems that are used for the provision of electric service in Minnesota. For this Interconnection Process the Area EPS Operator is Shakopee Public Utilities Commission.

Business Day – Monday through Friday, excluding Holidays as defined by Minn. Stat. §645.44, Subdivision 5. Any communication to have been sent or received after 4:30 p.m. Central Prevailing Time or on a Saturday, Sunday or holiday shall be considered to have been sent on the next Business Day.

Certified Equipment – Certified equipment is equipment that has been tested by a national recognized lab meeting a specific standard. For DER systems, UL 1741 listing is a common form of DER inverter certification. Additional information is seen in Section 15 and Section 14.

Confidential Information – Any confidential and/or proprietary information provided by one Party to the other Party and is clearly marked or otherwise designated "Confidential." All procedures, design, operating specifications, and metering data provided by the Interconnection Customer may be deemed Confidential Information. See Section 12.1 for further information.

Distributed Energy Resource (DER) – A source of electric power that is not directly connected to a bulk power system or central station service. DER includes both generators and energy storage technologies capable of exporting active power to an EPS. An interconnection system or a supplemental DER device that is necessary for compliance with this standard is part of a DER. For the purpose of the Interconnection Process and interconnection agreements, the DER includes the Customer's Interconnection Facilities but shall not include the Area EPS Operator's Interconnection Facilities.

Distribution System – The Area EPS facilities which are not part of the Local EPS, Transmission System or any generation system.

Distribution Upgrades – The additions, modifications, and upgrades to the Distribution System at or beyond the Point of Common Coupling to facilitate interconnection of the DER and render the distribution service necessary to effect the Interconnection Customer's connection to the Distribution System. Distribution Upgrades do not include Interconnection Facilities.

Electric Power System (EPS) – The facilities that deliver electric power to a load.

Fast Track Process – The procedure as described in the Interconnection Process - Fast Track Process for evaluating an Interconnection Application for a DER that meets the eligibility requirements of Section 3.4.

Force Majeure Event – An act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, an order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities, or another cause beyond a Party's control. A Force Majeure Event does not include an act of negligence or intentional wrongdoing.

Good Utility Practice – Any of the practices, methods and acts engaged in or approved by a significant portion of the electric industry during the relevant time period, or any of the practices, methods and act which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region.

Governmental Authority – Any federal, state, local or other governmental regulatory or administrative agency, court, commission, department, board, or other governmental subdivision, legislature, rulemaking board, tribunal, or other governmental authority having jurisdiction over the Parties, their respective facilities, or the respective services they provide, and exercising or entitled to exercise any administrative, executive, police, or taxing authority or power; provided, however, that such term does not include the Interconnection Customer, the Area EPS Operator, or any Affiliate thereof. The governing authority of the municipal utility is the authority governing interconnection requirements unless otherwise provided for in the Minnesota Technical Requirements.

Interconnection Agreement – The terms and conditions between the Area EPS Operator and Interconnection Customer (Parties). See Section 8 for when the Uniform Contract or Interconnection Agreement applies.

Interconnection Application – The Interconnection Customer's request to interconnect a new or modified, as described in Section 4, DER. See Simplified Application Form and Interconnection Application Form.

Interconnection Customer – The person or entity, including the Area EPS Operator, whom will be the owner of the DER that proposes to interconnect a DER(s) with the Area EPS Operator's Distribution System. The Interconnection Customer is responsible for ensuring the DER(s) is designed, operated and maintained in compliance with the Minnesota Technical Requirements.

Interconnection Facilities – The Area EPS Operator's Interconnection Facilities and the Interconnection Customer's Interconnection Facilities. Collectively, Interconnection Facilities include all facilities and equipment between the DER and the Point of Common Coupling, including any modification, additions or upgrades that are necessary to physically and electrically interconnect the DER to the Area EPS Operator's System. Some examples of Customer Interconnection Facilities include: supplemental DER devices, inverters, and associated wiring and cables up to the Point of DER Connection. Some examples of Area EPS Operator Interconnection Facilities include sole use facilities; such as, line extensions, controls, relays, switches, breakers, transformers and shall not include Distribution Upgrades or Network Upgrades.

Interconnection Process – The Area EPS Operator's interconnection standards in this document.

Material Modification – A modification to machine data, equipment configuration or to the interconnection site of the DER at any time after receiving notification by the Area EPS Operator of a complete Interconnection Application that has a material impact on the cost, timing, or design of any Interconnection Facilities or Upgrades, or a material impact on the cost, timing or design of any Interconnection Application with a later Queue Position or the safety or reliability of the Area EPS.[6]

MN Technical Requirements – The term including all of the DER technical interconnection requirement documents for the state of Minnesota; including Attachment 2 Distributed Generation Interconnection Requirements established in the Commission's September 28, 2004 Order in E-999/CI-01-1023) until superseded and upon Commission approval of updated Minnesota DER Technical Interconnection and Interoperability Requirements in E-999/CI-16-521 (anticipated July 2019.)

Nameplate Rating – nominal voltage (V), current (A), maximum active power (kWac), apparent power (kVA), and reactive power (kVar) at which a DER is capable of sustained operation. For a Local EPS with multiple DER units, the aggregate nameplate rating is equal to the sum of all

---

[6] A Material Modification shall include, but may not be limited to, a modification from the approved Interconnection Application that: (1) changes the physical location of the point of common coupling; such that it is likely to have an impact on technical review; (2) increases the nameplate rating or output characteristics of the Distributed Energy Resource; (3) changes or replaces generating equipment, such as generator(s), inverter(s), transformers, relaying, controls, etc., and substitutes equipment that is not like-kind substitution in certification, size, ratings, impedances, efficiencies or capabilities of the equipment; (4) changes transformer connection(s) or grounding; and/or (5) changes to a certified inverter with different specifications or different inverter control settings or configuration. A Material Modification shall not include a modification from the approved Interconnection Application that: (1) changes the ownership of a Distributed Energy Resource; (2) changes the address of the Distributed Energy Resource, so long as the physical point of common coupling remains the same; (3) changes or replaces generating equipment such as generator(s), inverter(s), solar panel(s), transformers, relaying, controls, etc. and substitutes equipment that is a like-kind substitution in certification, size, ratings, impedances, efficiencies or capabilities of the equipment; and/or (4) increases the DC/AC ratio but does not increase the maximum AC output capability of the Distributed Energy Resource in a way that is likely to have an impact on technical review.

DERs nameplate rating in the Local EPS. For purposes of the Attachment V in the Interconnection Agreement, the DER system's capacity may, with the Area EPS's agreement, be limited thought use of control systems, power relays or similar device settings or adjustments as identified in IEEE 1547. The nameplate ratings referenced in the Interconnection Process are alternating current nameplate DER ratings at the Point of DER Coupling.

Network Upgrades – Additions, modifications, and upgrades to the Transmission System required at or beyond the point at which the DER interconnects with the Area EPS Operator's System to accommodate the interconnection with the DER to the Area EPS Operator's System. Network Upgrades do not include Distribution Upgrades.

Operating Requirements – Any operating and technical requirements that may be applicable due to the Transmission Provider's technical requirements or Minnesota Technical Requirements, including those set forth in the Interconnection Agreement.

Party or Parties – The Area EPS Operator and the Interconnection Customer.

Point of Common Coupling (PCC) – The point where the Interconnection Facilities connect with the Area EPS Operator's Distribution System. See figure 1. Equivalent, in most cases, to "service point" as specified by the Area EPS Operator and described in the National Electrical Code and the National Electrical Safety Code.

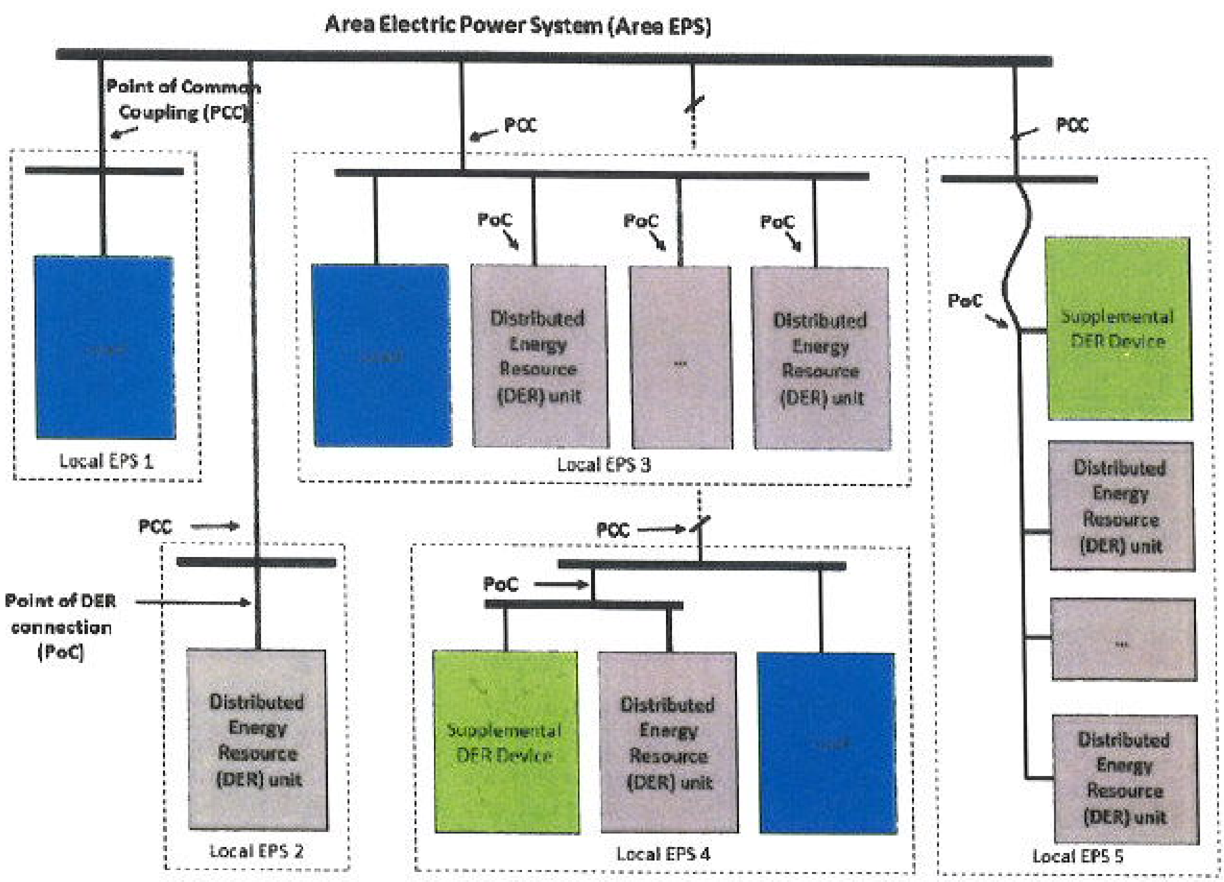


Figure 1: Point of Common Coupling and Point of DER Connection

(Source: IEEE 1547)

Point of DER Connection (PoC) – When identified as the Reference Point of Applicability, the point where an individual DER is electrically connected in a Local EPS and meets the requirements of this standard exclusive of any load present in the respective part of the Local EPS (e.g. terminals of the inverter when no supplemental DER device is required.) For DER unit(s) that are not self-sufficient to meet the requirements without a supplemental DER device(s), the Point of DER Connection is the point where the requirements of this standard are met by DER in conjunction with a supplemental DER device(s) exclusive of any load present in the respective part of the Local EPS.

Queue Position – The order of a valid Interconnection Application, relative to all other pending valid Interconnection Applications, that is established based upon the date- and time- of receipt of the complete Interconnection Application as described in Section 4.7.

Reasonable Efforts – With respect to an action required to be attempted or taken by a Party under these procedures, efforts that are timely and consistent with Good Utility Practice and are otherwise substantially equivalent to those a Party would use to protect its own interests.

Reference Point of Applicability – The location, either the Point of Common Coupling or the Point of DER Connection, where the interconnection and interoperability performance requirements specified in IEEE 1547 apply. With mutual agreement, the Area EPS Operator and Customer may determine a point between the Point of Common Coupling and Point of DER Connection. See Minnesota Technical Requirements for more information.

Simplified Process – The procedure for evaluating an Interconnection Application for a certified inverter-based DER no larger than 20 kW that uses the screens described in the Interconnection Process – Simplified Process document. The Simplified Process includes simplified procedures.

Study Process – The procedure for evaluating an Interconnection Application that includes the scoping meeting, system impact study, and facilities study.

Transmission Owner – The entity that owns, leases or otherwise possesses an interest in the portion of the Transmission System relevant to the Interconnection.

Transmission Provider – The entity (or its designated agent) that owns, leases, controls, or operates transmission facilities used for the transmission of electricity. The term Transmission Provider includes the Transmission Owner when the Transmission Owner is separate from the Transmission Provider. The Transmission Provider may include the Independent System Operator or Regional Transmission Operator.

Transmission System – The facilities owned, leased, controlled or operated by the Transmission Provider or the Transmission Owner that are used to provide transmission service. See the

Commission's July 26, 2000 Order Adopting Boundary Guidelines for Distinguishing Transmission from Generation and Distribution Assets in Docket No. E-999/CI-99-1261.

Uniform Contract – the Area EPS Operator's Agreement for Cogeneration and Small Power Production Facilities (Uniform Contract) that may be applied to all qualifying new and existing interconnections between the Area EPS Operator and an DER system having capacity less than 40 kilowatts.

Upgrades – The required additions and modifications to the Area EPS Operator's Transmission or Distribution System at or beyond the Point of Interconnection. Upgrades may be Network Upgrades or Distribution Upgrades. Upgrades do not include Interconnection Facilities.

14 Certification of DER Equipment

Distributed Energy Resource (DER) equipment proposed for use in an interconnection system shall be considered certified for interconnected operation if the following criteria is met:

1) It has been tested in accordance with industry standards for continuous utility interactive operation in compliance with the appropriate codes and standards referenced below by any Nationally Recognized Testing Laboratory (NRTL) recognized by the United States Occupational Safety and Health Administration to test and certify interconnection equipment pursuant to the relevant codes and standards listed in the Overview Process,

2) It has been labeled and is publicly listed by such NRTL at the time of the interconnection application and,

3) Such NRTL makes readily available for verification all test standards and procedures it utilized in performing such equipment certification, and, with consumer approval, the test data itself. The NRTL may make such information available on its website and by encouraging such information to be included in the manufacturer's literature accompanying the equipment.

The Interconnection Customer must verify that the assembly and use of the equipment falls within the use or uses for which the equipment was tested, labeled, and listed by the NRTL.

Certified equipment shall not require further type-test review, testing, or additional equipment to meet the requirements of this interconnection procedure; however, nothing herein shall preclude the need for a DER Design Evaluation or an on-site commissioning test by the parties to the interconnection as provided for in the Minnesota Technical Requirements.

If the certified equipment package includes only interface components (switchgear, inverters, or other interface devices), then an Interconnection Customer must show that the generator or other electric source being utilized with the equipment package is compatible with the equipment package and is consistent with the testing and listing specified for this type of interconnection equipment.

Provided the generator or electric source, when combined with the equipment package, is within the range of capabilities for which it was tested by the NRTL, and does not violate the interface components' labeling and listing performed by the NRTL, no further type-test review, testing or additional equipment on the customer side of the Point of Common Coupling shall be required to be considered certified for the purposes of this interconnection procedure; however, nothing herein shall preclude the need for a DER Design Evaluation or an on-site commissioning test by the parties to the interconnection as provided for in the Minnesota Technical Requirements.

An equipment package does not include equipment provided by the Area EPS.

15 Certification Codes and Standards

The existing Minnesota Technical Requirements and the following standards shall be used in conjunction with the Interconnection Process. The process has started to update the Technical Requirements to meet IEEE 1547-2018. Once that process is completed, the updated DER Technical Interconnection and Interoperability Requirements will supersede this section.

When the stated version of the following standards is superseded by an approved revision then that revision shall apply:

IEEE 1547-2003 IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems

IEEE 1547a-2014 IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems – Amendment 1

IEEE 1547.1-2005 IEEE Standard Conformance Test Procedures for Equipment Interconnecting Distributed Resources with Electric Power Systems

IEEE 1547.1a-2015 (Amendment to IEEE Std 1547.1-2005) IEEE Standard Conformance Test Procedures for Equipment Interconnecting Distributed Resources with Electric Power Systems – Amendment 1

UL 1741 Inverters, Converters, Controllers, and Interconnection System Equipment for Use in Distributed Energy Resources (2010)

NFPA 70 (2017), National Electrical Code

IEEE Std C37.90.1 (2012) (Revision of IEEE Std C37.90.1-2002), IEEE Standard for Surge Withstand Capability (SWC) Tests for Protective Relays and Relay Systems Associated with Electric Power Apparatus

IEEE Std C37.90.2 (2004) (Revision of IEEE Std C37.90.2-1995), IEEE Standard for Withstand Capability of Relay Systems to Radiated Electromagnetic Interference from Transceivers

IEEE Std C37.108-20021989 (Revision of C37.108-19892002), IEEE Guide for the Protection of Network Transformers

IEEE Std C57.12.44-2014 (Revision of IEEE Std C57.12.44-2005), IEEE Standard Requirements for Secondary Network Protectors

IEEE Std C62.41.2-2002, IEEE Recommended Practice on Characterization of Surges in Low-Voltage (1000 V and Less) AC Power Circuits

IEEE Std C62.41.2-2002_Cor 1-2012 (Corrigendum to IEEE Std C62.41.2-2002) – IEEE Recommended Practice on Characterization of Surges in Low-Voltage (1000 V and Less) AC Power Circuits Corrigendum 1: Deletion of Table A.2 and Associated Text

IEEE Std C62.45-2002 (Revision of IEEE Std C62.45-1992) – IEEE Recommended Practice on Surge Testing for Equipment Connected to Low-Voltage (1000 V and less) AC Power Circuits

ANSI C84.1-(2016) Electric Power Systems and Equipment – Voltage Ratings (60 Hertz)

IEEE Standards Dictionary Online, [Online]

NEMA MG 1-2016, Motors and Generators

IEEE Std 519-2014, IEEE Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems

SCHEDULE 4 – UTILITY AVOIDED ENERGY, CAPACITY AND RENEWABLE ENERGY CREDIT RATES

Qualifying Facilities that qualify and select the Simultaneous Purchase and Sale or Time-of-Day rates for compensation from Utility for all generation shall be compensated by Utility as detailed in Parts N and O of the Utility's Rules Governing the Interconnection of Cogeneration and Small Power Productions Facilties. Compensation will be based on the rates as follows:

	Energy ($/kWh)	Capacity ($/kWh)	REC ($/kWh)
Summer Months (June-Sept)			
On Peak	$0.0329	$0.0000	$0.0000
Off Peak	$0.0215	$0.0000	$0.0000
All Hours	$0.0267	$0.0000	$0.0000
Winter Months (Oct-May)			
On Peak	$0.0312	$0.0000	$0.0000
Off Peak	$0.0233	$0.0000	$0.0000
All Hours	$0.0270	$0.0000	$0.0000
Annual (January-December)	$0.0269	$0.0000	$0.0000

Shakopee Public Utilities

"Lighting the Way – Yesterday, Today and Beyond"

April 25, 2019

TO: John Crooks, Utilities Manager JRC

FROM: Greg Drent, Electric Superintendent

Subject: Certificate of Excellence in Reliability

Background

American Public Power Association (APPA) recently honored 143 public power utilities with a "certificate of excellence" for reliable performance, as shown by comparing their outage records against nationwide data gathered by the Energy Information Administration.

The utilities that were recognized by the Association have been keeping track of their reliability data via the Association's web-based subscription service, called eReliability tracker, which lets utilities collect, categorize and summarize their outage information. Subscribing utilities use the eReliability Tracker Service to store their outages and restoration data and run reports throughout the year. At the end of the year, the Association benchmarks their data against national statistics from EIA, which is a branch of the Department of Energy.

Utilities that placed in the top quartile of reliability nationwide, as measured against the EIA's data on System Average Interruption Duration Index, or SAIDI, received the certificate of excellence, the EIA information comes from the agency's annual surveys of electric power utilities via EIA 861.

SPU System Overview

I am pleased that SPU has achieved the certificate of excellence in reliability in 2017 and 2018. We work hard to make sure the downtime to our customers is minimal. We have a very aggressive tree trimming policy and this is a substantial reason storm related damage is usually minimal. We also require a 30-minute response time on all after-hours outages. Our linemen take pride in the installation and maintenance of our electric system and it shows in our reliability numbers.

We use eReliability to track outages and use the software for benchmarking to proactivity maintain the electric system. We are able to use the data on our system to identify our worst performing circuits. These circuits get additional attention to address the problems. We were able to identify the issues that squirrels were causing on our system so we are currently adding pole wrap on all poles to address the problem. We were also able to put a pole inspection program in place to find all rotten poles on our system and replace them before they cause an outage.

It is an honor for the utility to get this award two years in a row. We address any problems on our system to continue our success. We will make every effort possible to achieve this award in the future.

Presentation of CERTIFICATE OF EXCELLENCE IN RELIABILITY plaque to the commission.

SHAKOPEE PUBLIC UTILITIES
2019
RELIABILITY AND OUTAGE REPORT

SHAKOPEE PUBLIC UTILITIES COMMISSION
2019 ELECTRIC OUTAGE AND RELIABILITY REPORT

Electric System Reliability is the ability of an electric system to perform its functions under normal and extreme circumstances.

Overall system design, substation and distribution design, fusing schemes, and the many independent system components for the electric distribution system impacts fundamental reliability.

Data on Outages of Shakopee Public Utilities (SPU) Electrical System were acquired throughout the year. The responding SPU line crew, at the end of the electrical outage, completes the outage report. The report information includes the cause of the electrical outage, substation circuit number, number of customers, date, estimated time the outage occurred and the time when the electricity was restored. At the end of the year, the outage data was compiled and is described in the first part of this report. As a procedure, Shakopee Public Utilities Engineering and Operations analyze these statistics to determine areas of concentration for electrical system improvement.

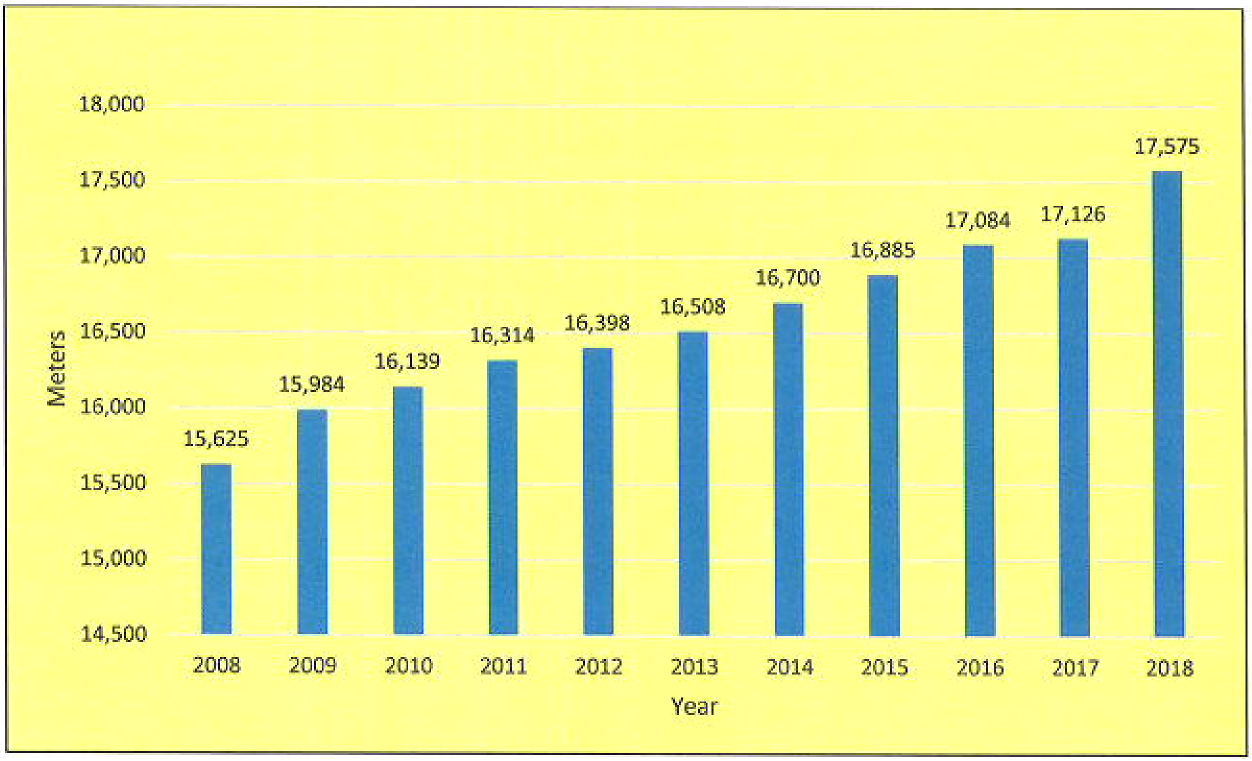
Shakopee Public Utilities Reliability Indices are also derived from this data and are reported in the later part of the report. We are required by Minnesota State Statute 216B.029 to provide this report, annually, to the Utility's Governing Body.

The Shakopee Electric Department provides customer service, constructs and maintains SPU's electric distribution system and the City of Shakopee street light system. SPU electric distribution system consists of approximately 23% overhead and 77% underground facilities. The system has 5 substations with 33 distribution circuits. There are 298 miles of underground lines and 89.2 miles of overhead lines. The system includes 3,257 power poles, 634 overhead transformers and 2,350 pad mount transformers for the underground areas.

How the Shakopee Public Utilities Planning and Engineering Department designs the electric system and how the Electric Department constructs, operates and maintains it and how the Line Crews respond to the outages; continues to leave a positive impact on the SPU Electrical System Reliability Performance. The reliability statistics are the basis for good decision making. In general, reliability statistics are excellent for self-evaluation and provide a method to assess the performance and dependability of SPU's electric distribution system. They also can be utilized to compare statistics with previous SPU and other Electric Companies Reliability Statistics.

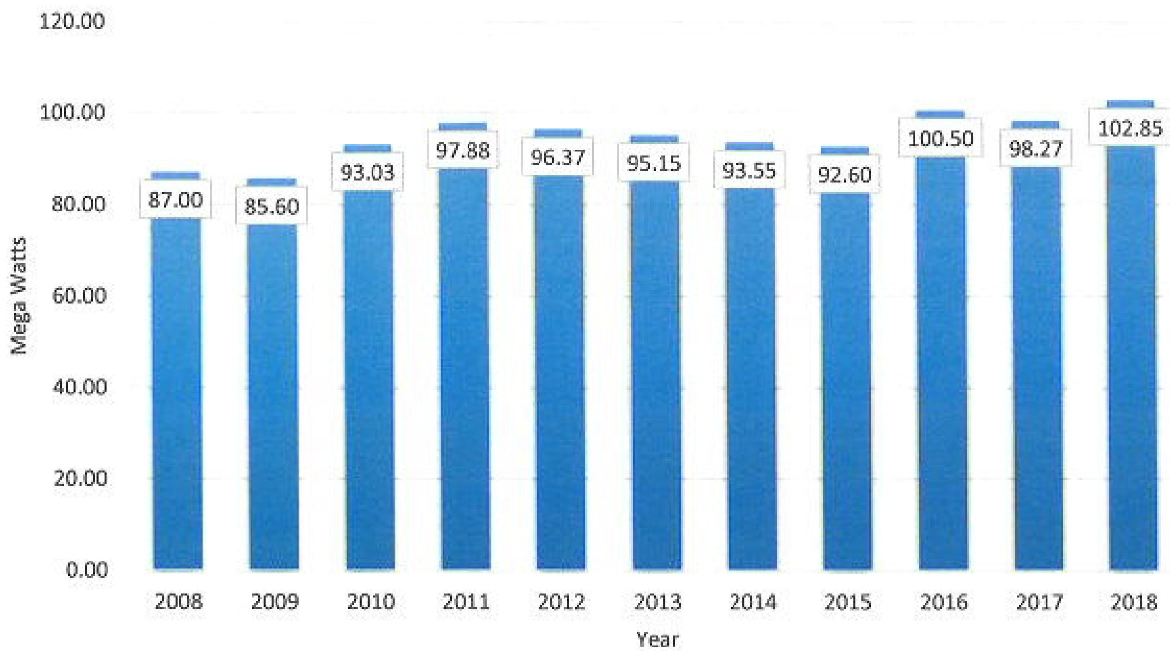
Shakopee Public Utilities Electric Meters

Shakopee Utilities 2018 customers number reached **17,575** electric meters. SPU has had continued growth in electric meters as shown in the graph below.



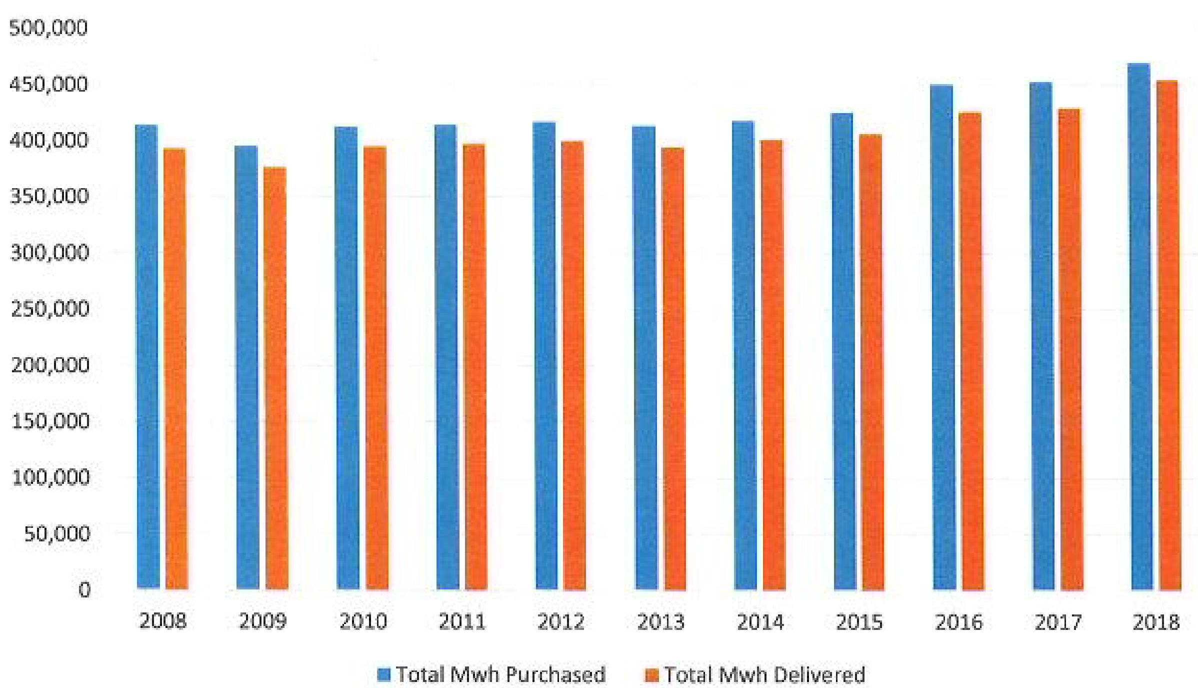
Coincidental Peak System Demand

Shakopee Public Utilities 2018 15-Minute Coincidental Peak Electric System Demand was 102.85 Mega Watts.



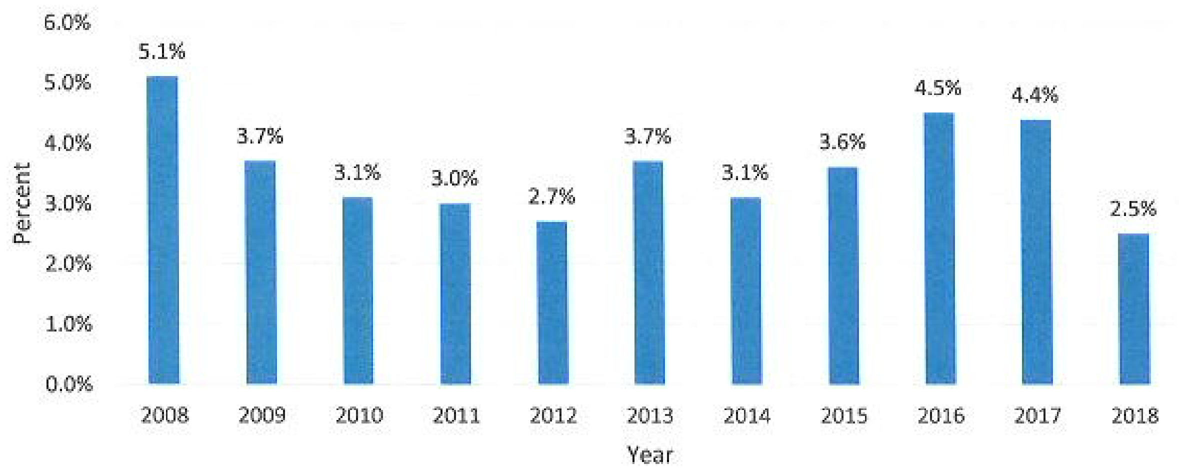
Mega Watt Hour Purchased and Delivered

SPU purchased 469,262 MWh and sold 454,234 MWh of electricity during 2018.



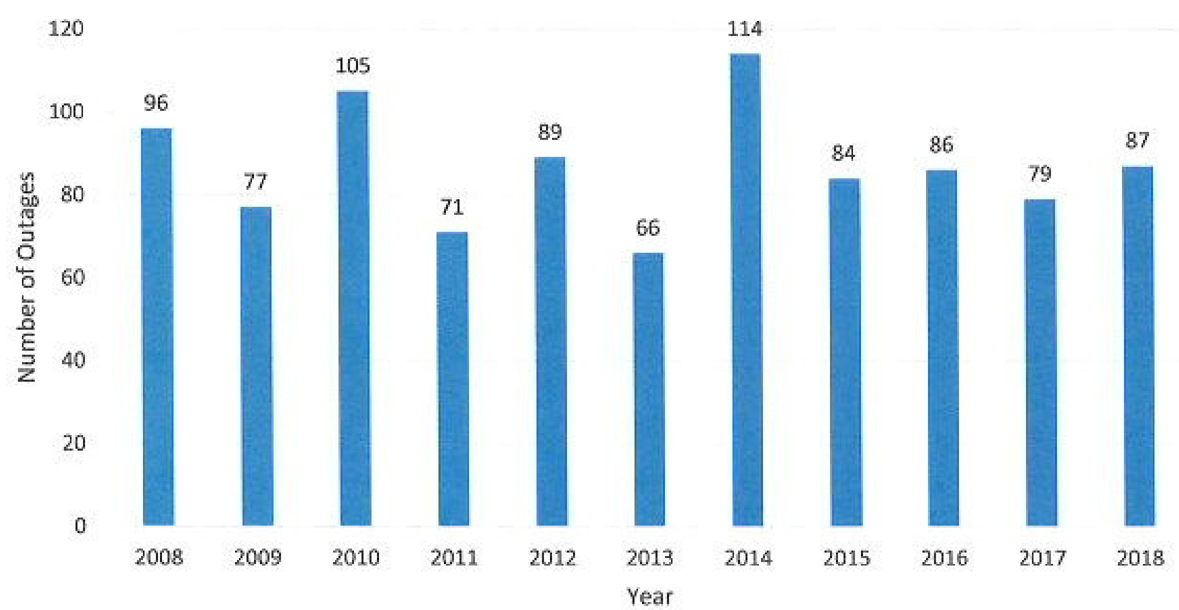
Unaccounted for KWH (Line Loss)

Line Loss is the difference between the amount of total kilowatt-hours purchased and the total kilowatt-hours delivered. All electric companies have unaccounted loss of kWh associated with the operation of a distribution system. Common reasons for the losses are impedance and reactance in conductors, transformer excitation current, magnetizing inductance, power theft and inaccurate metering. Keeping track of losses reflects the efficiencies of the design and operation of the system. Shakopee Utilities did not account for 11,521,822 kWh of power during 2018. This is a loss of 2.5%, which is down from 4.4% in 2017 of the power purchased.



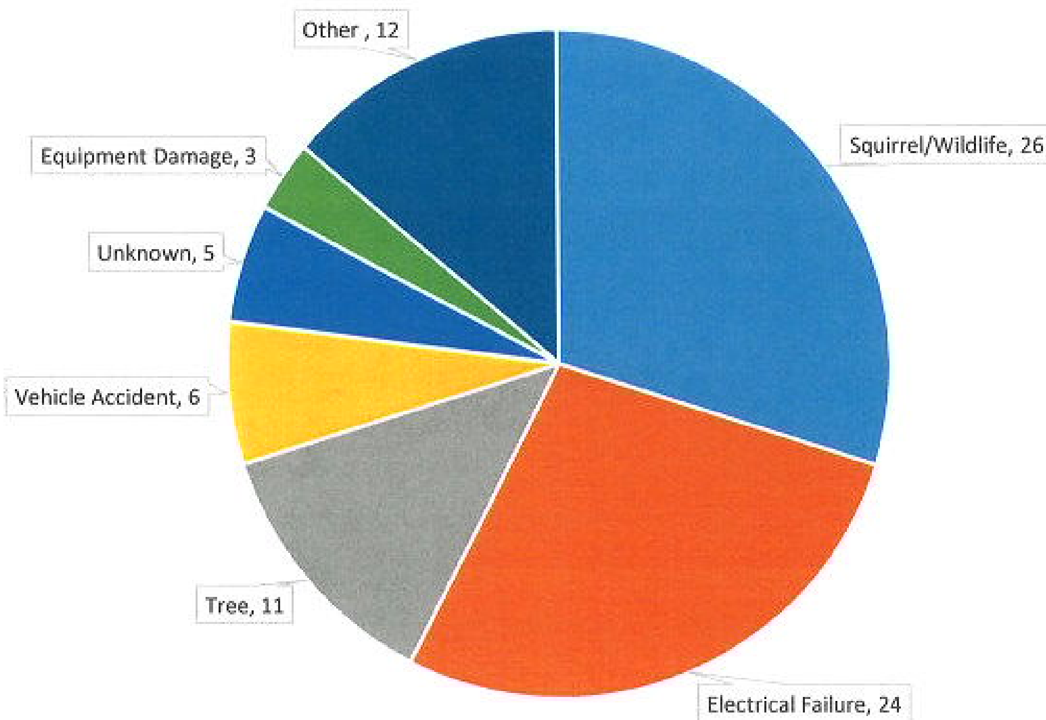
Outage Response

SPU has recorded outages for a 24-year period. During 2018, SPU Crews responded to 87 outages on the electric distribution system.



Outage Causes

The leading cause of power outages on SPU electrical system was due to animals. SPU had twenty-six (26) outages by animals and twenty-four (24) by electrical failure on its electric distributions system. Twenty-one of the animal outages were caused by squirrels. Twelve outages are categorized under other which includes: lightning, contractor dig-in, equipment, birds, worn out equipment, vines and contact with a foreign object.



Circuit Performance

Shakopee Public Utilities' Shakopee South circuit SS 32 from the Shakopee South 1 Substation, had the most electrical outages with 16 outages. Five (5) of the outages were caused by squirrels and another four (4) were caused by electrical failure. In 2017 SS 32 had only two (2) outages caused by squirrels.

To evaluate the reliability of the electrical system, reliability indices are used. The most commonly used reliability indices are **SAIFI, SAIDI, CAIDI** and **ASAI.** The definitions of these indices are described below and are consistent with IEEE Std. 1366-2003 "IEEE Guide for Electric Power Distribution Reliability Indices".

SAIFI - System Average Interruption Frequency Index

The average number of sustained outages that a customer would experience in a year.

$$\text{SAIFI} = \frac{\text{Total Number of Customer Interruptions (>5 minutes)}}{\text{Total Number of Customers Served}}$$

SPU 2018 SAIFI 0.21

SAIDI – System Average Interruption Duration Index

The average amount of time a customer on the utility's system spent without power during the year.

$$\text{SAIDI} = \frac{\text{Number of Customer-Minutes Interrupted (>5 minutes)}}{\text{Total Number of Customers Served}}$$

SPU 2018 SAIDI 13.58 minutes

CAIDI – Customer Average Interruption Duration Index

The average amount of time a customer can expect to be without power when they lose power.

$$\text{CAIDI} = \frac{\text{Number of Customer-Minutes Interrupted (>5 minutes)}}{\text{Number of Customers Interrupted (>5 minutes)}}$$

SPU 2018 CAIDI 64.55 minutes

ASAI – Average Service Availability Index

Represents the fraction of time that a customer has received power during the year 2018.

$$\text{ASAI} = \frac{\text{Customer Hours Service Availability}}{\text{Number of Customers X (No. of hours/year)}}$$

SPU 2018 ASAI 99.997

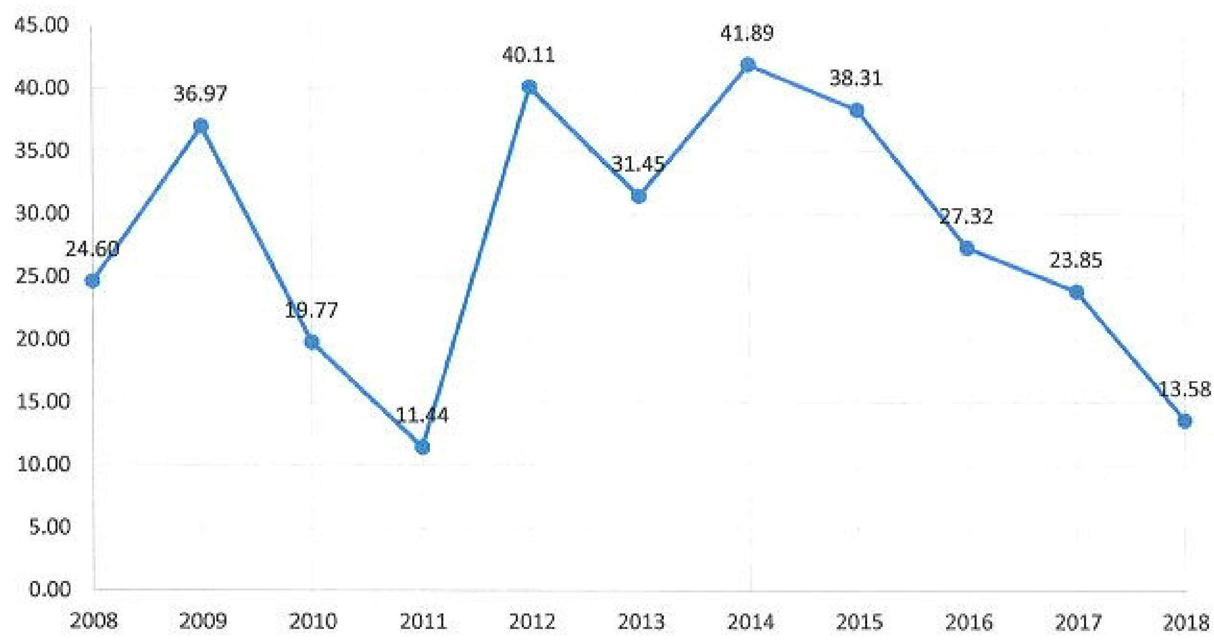
Shakopee Utilities Ten Year Statistics

SAIFI – System Average Interruption Frequency Index

The average number of sustained outages that a customer would experience in a year.

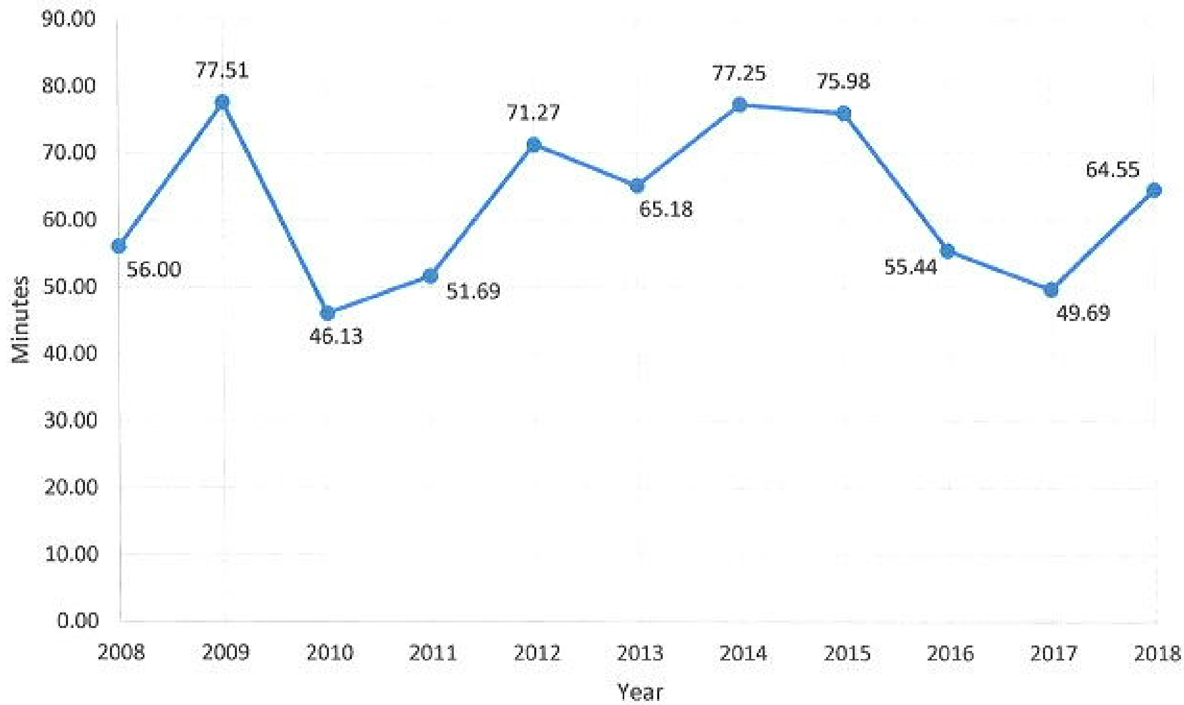
SAIDI – System Average Interruption Duration Index

The average amount of time a customer on the utility's system spent without power during the year.



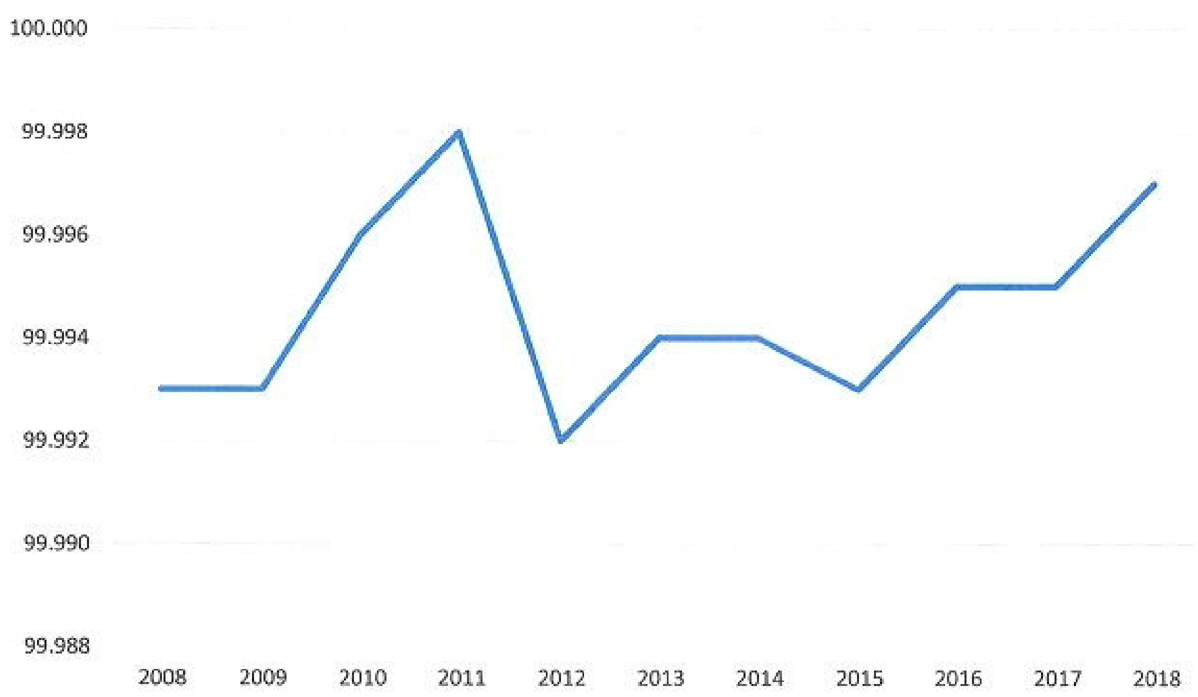
CAIDI – Customer Average Interruption Duration Index

The average amount of time a customer can expect to be without power when they lose power.



ASAI – Average Service Availability Index

Represents the fraction of time that a customer has received power during the year 2018.



Comparison with Xcel Energy and Minnesota Valley

	SPU 2018	Xcel Metro West 2018 Proposed	Xcel South East 2018 Proposed	MN Valley 2018
SAIFI	0.21	0.83	0.78	0.43
SAIDI	13.58	85.17	102.39	63.18
CAIDI	64.55	102.46	131.46	146.16

Comparison with Regional Public Power Utilities and National Average

Shakopee Public Utilities participated in the American Public Power Association (APPA) 2018 Annual Benchmarking Report of public owned power systems. The results of the survey were published in March 2019. Minnesota is in APPA's Region 3 with North Dakota, South Dakota, Nebraska, Kansas, Iowa and Missouri.

	SPUC 2018	Region 3 Average 2018	National Average 2018
SAIFI	0.21	0.67	1.08
SAIDI	13.58	67.35	55.13
CAIDI	64.55	173.97	139.73
ASAI	99.997	99.975	99.960

Respectfully Submitted,

Greg Drent

Electric Superintendent

April 26, 2019

9e

SHAKOPEE PUBLIC UTILITIES
MEMORANDUM

TO: SHAKOPEE PUBLIC UTILITIES COMMISSSION

FROM: JOHN R. CROOKS, UTILITIES MANAGER JRC

SUBJECT: MMPA BOARD MEETING PUBLIC SUMMARY APRIL 2019

DATE: MAY 1, 2019

The Board of Directors of the Minnesota Municipal Power Agency (MMPA) met on April 23, 2019 at the Agency's Faribault Energy Park power plant in Faribault, Minnesota.

The Board approved MMPA's 2018 audit report. The report can be found on MMPA's website at http://www.mmpa.org/about/financials-reports/

The Board also approved an Amended and Restated Revolving Credit Agreement with US Bank. This agreement extends MMPA's $20 million credit facility for another three years.

The Board discussed the status of the renewable projects the Agency is pursuing.

The revised Minnesota Interconnection Process for distributed energy resources was discussed. MMPA passed a motion requesting that each MMPA member's governing body approve two resolutions on this subject before June 17, 2019.

Participation in MMPA's residential Clean Energy Choice program increased over March, with a market penetration that is now at 3.1%.

10a

Shakopee Public Utilities

"Lighting the Way – Yesterday, Today and Beyond"

May 1, 2019

TO: John Crooks, Utilities Manager JRC

FROM: Renee Schmid, Director of Finance and Administration RS

SUBJECT: 2018 Total Compensation and Benefits Summary

Background

Each year the Shakopee Public Utilities Commission establishes a list of goals and objectives to accomplish for the year. One of the goals set by the Commission was to develop a report for each employee showing the total value of our compensation and benefits package. The Commission's intent was to make this report available to every employee on an annual basis.

Staff has completed the distribution of the 2018 Total Compensation and Benefits Summary report and related cover memo.

Action Requested

No formal action requested.

11a

Shakopee Public Utilities

"Lighting the Way – Yesterday, Today and Beyond"

April 30, 2019

TO: John Crooks, Utilities Manager JRC

FROM: Sharon Walsh, Director of Marketing and Customer Relations SW

SUBJECT: 2019 Tom Bovitz Scholarship – MMUA Award Recipient

Overview

We are proud that our first place winner of the SPU-sponsored Tom Bovitz Memorial Scholarship, Shelby Zander, was entered into the MMUA statewide competition and was awarded third place for her essay. She received an additional $1,000 scholarship from MMUA for this submission.

This information will be shared with the Shakopee community via a facebook post and photo.

The second place winner of the SPU-sponsored Tom Bovitz Memorial Scholarship was Mr. Alan Purves. He received a $500 scholarship from SPU.

Action Requested

No action is required.

Post Office Box 470 • 255 Sarazin Street • Shakopee, Minnesota 55379-0470
(952) 445-1988 • Fax (952) 445-7767 • www.spucweb.com

11b

SHAKOPEE PUBLIC UTILITIES

"Lighting the Way – Yesterday, Today and Beyond"

April 22, 2019

TO: John Crooks, Utilities Manager JRC

FROM: Renee Schmid, Director of Finance and Administration

SUBJECT: Insurance Liability Coverage - Waiver

Overview

- Staff is in the process of renewing the Utilities Property and Liability Insurance Coverage for the coming year. In order to extend coverage, the Commission is required to make a decision to either "waive" or "not waive" the monetary limits on municipal tort liability. More information regarding the implications of this decision is included in the attached waiver form from the League of Minnesota Cities.

Recommendation

- Staff recommends the commission elect to "not waive" the monetary limits as a measure to limit any future claims exposure.

Requested Action by Commission

The Commission is asked to make a decision on tort liability limits and select one option below:

- The Commission **DOES NOT WAIVE** the monetary limits on municipal tort liability established by Minnesota Statues, Section 466.04
- The Commission **WAIVES** the monetary limits on municipal tort liability established by Minnesota Statues, Section 466.04 to the extent of the limit on the liability coverage obtained from LMCIT.

LEAGUE OF MINNESOTA CITIES

CONNECTING & INNOVATING
SINCE 1913

LIABILITY COVERAGE – WAIVER FORM

Members who obtain liability coverage through the League of Minnesota Cities Insurance Trust (LMCIT) must complete and return this form to LMCIT before the member's effective date of coverage. Return completed form to your underwriter or email to pstech@lmc.org.

The decision to waive or not waive the statutory tort limits must be made annually by the member's governing body, in consultation with its attorney if necessary.

Members who obtain liability coverage from LMCIT must decide whether to waive the statutory tort liability limits to the extent of the coverage purchased. The decision has the following effects:

- *If the member does not waive the statutory tort limits*, an individual claimant could recover no more than $500,000 on any claim to which the statutory tort limits apply. The total all claimants could recover for a single occurrence to which the statutory tort limits apply would be limited to $1,500,000. These statutory tort limits would apply regardless of whether the member purchases the optional LMCIT excess liability coverage.
- *If the member waives the statutory tort limits and does not purchase excess liability coverage*, a single claimant could recover up to $2,000,000 for a single occurrence (under the waive option, the tort cap liability limits are only waived to the extent of the member's liability coverage limits, and the LMCIT per occurrence limit is $2,000,000). The total all claimants could recover for a single occurrence to which the statutory tort limits apply would also be limited to $2,000,000, regardless of the number of claimants.
- *If the member waives the statutory tort limits and purchases excess liability coverage*, a single claimant could potentially recover an amount up to the limit of the coverage purchased. The total all claimants could recover for a single occurrence to which the statutory tort limits apply would also be limited to the amount of coverage purchased, regardless of the number of claimants.

Claims to which the statutory municipal tort limits do not apply are not affected by this decision.

LMCIT Member Name: ____

Check one:

☐ The member **DOES NOT WAIVE** the monetary limits on municipal tort liability established by Minn. Stat. § 466.04.

☐ The member **WAIVES** the monetary limits on municipal tort liability established by Minn. Stat. § 466.04, to the extent of the limits of the liability coverage obtained from LMCIT.

Date of member's governing body meeting: ______________________________

Signature: ______________________________ Position: ______________________________

11c

SHAKOPEE PUBLIC UTILITIES
MEMORANDUM

TO: SHAKOPEE PUBLIC UTILITIES COMMISSION

FROM: JOHN R. CROOKS, UTILITIES MANAGER JRC

SUBJECT: MMUA RESOURCE ARTICLE "A SITUATION BEST AVOIDED"

DATE: MAY 2, 2019

With the SPU financial audit being presented and accepted at the last Commission meeting, the attached article from the MMUA publication RESOURCE is worth reading.

Financial challenges that happen without proper financial management can create situations that no municipal utility wants to find itself in.

The Resource
April 2019

MMUA

A situation best avoided

Govern your utility so it can withstand financial challenges and thrive for future generations

The sale and lease-back agreement between the city of Biwabik and Minnesota Power outlined elsewhere in this newsletter is certainly innovative and may well have staved off the sale of the storm-damaged municipal system. It needs to be said, however, that including the story in this newsletter should not be taken as endorsement of the arrangement.

The reason for that is simple: it moves the municipal utility one step closer to an eventual sell-out.

It is a situation no municipal utility wants to find itself in (such as the Federated-Truman buy-out offer). Rather, the situation is highlighted to show just how slender is the thread that keeps many cities in the municipal utility business, and to stimulate thought on how to best protect and promote the health of your utility.

It is a rare city administrator or clerk that doesn't readily acknowledge the value of a city-owned electric utility. That doesn't necessarily translate, however, into the political will to properly budget for and fund utility operations.

MMUA regularly holds meetings with speakers addressing the topics of utility rates and reserves. Maintaining adequate reserves improves the city/utility financial position and also serves as a cushion for that day when an electric system faces significant investment or suffers catastrophe from ice, wind or flood.

Realizing the value of a municipal electric or natural gas system, it should be one goal of the astute municipal policymaker to better ensure the future viability of that system, not to use the utility primarily as a 'cash cow' to fund today's disparate endeavors.

Proper financial management is necessary, as is quantifying the various benefits provided by the utility. (If you would like a checklist to help you do this, please contact us.)

While taking no official position on the topic—which has raged as long as municipal utilities have existed—one benefit of placing the operation of the municipal utility under the governance of a utilities commission is that it creates one more hurdle, and level of scrutiny, should any proposal to sell a system arise.

While either form of governance can be successful depending on the people involved, statutes governing commissions mandate accounting which endeavors to eliminate cross-subsidy between the various enterprises entrusted to commission governance.

A commission, if conducting its business properly, also provides a level of attention to utility operations that a city council—its attention diverted to many different issues—is unlikely to provide. (The author distinctly recalls one city council meeting where a variance for a garage consumed 45 minutes of a meeting and a proposal for a $3.5 million substation improvement was unanimously approved in five minutes.)

The flip side of the council-commission debate is that issues occasionally divide a council from a commission and lead to local political turmoil. And, it is axiomatic for many municipal operations, that with limited resources available, everybody with the city has to 'pitch in' when a need arises.

A municipal utility must necessarily benefit the city and its citizens; but it is also true that times may arise when ratepayers will have to assume a temporary burden to improve and expand utility services.

Thus honest discussion conducted with goodwill and an overarching commitment to the good of the city, and the protection of its most valuable asset, is necessary to ensure efficient operation and future viability.

The topic brings to mind these words, from the 1933 Worthington city clerk to an interested party in Staples, in regards to the establishing of a municipal electric plant: "All we have said may be summarized in this one statement: We believe that a municipally-owned plant is an advisable undertaking if the citizens are wise in their handling of its affairs."

Truer words were never spoken.

Both those utilities thrive today.

Are you doing your duty today to ensure the future viability of your utility?

The editor

11d

SHAKOPEE PUBLIC UTILITIES
MEMORANDUM

TO: SHAKOPEE PUBLIC UTILITIES COMMISSION

FROM: JOHN R. CROOKS, UTILITIES MANAGER JRC

SUBJECT: SPU COMMISSION GOALS AND OBJECTIVES - 2019

DATE: MAY 3, 2019

The following 6 items were discussed at the March 18 Commission Goals and Objectives Workshop. Staff is in the process of preparing detailed work plans for each item. Included with this agenda item are work plans (as they exist today) that are already in progress; website development, succession planning and the communications plan. When completed the work plans for AMR Implementation and the GIS Roadmap will be brought back to the Commission for review.

IT and Security Assessment will need to be handled separately and within the Utility, as there would be limited information that should be discussed at public meetings.

1. **Website Development** – 2018 carryover
2. **Succession/Transition Plans for Key Positions** – 2018 carryover
3. **Automatic Meter Reading Implementation -**
4. **5 Year Strategic Geographic Information System Plan (GIS) -**
5. **Development of a Strategic Communications Plan –**
6. **Information Technology and Security Assessment** – ongoing

SPU WEBSITE
Project Overview and Definition

Redesign the SPU website to improve the internal and external functionality, enhancing the public appeal and driving customers to the site as a primary communications and contact source. Interactive features to include online bill payment, job and service applications, equipment purchases, conservation submissions, power-outage management tools, form downloads and fee payments. A stronger, more efficient search tool for documents, white papers, specific topics and general information, as well as an enhanced site plan for improved customer navigation are also to be included.

SPU will utilize third party expertise to develop the site plan and web design elements. Internal Marketing Director will assist department directors to develop appropriate content. Ongoing maintenance of the web content will require involvement from all departments to keep information current and relevant, with current event postings managed by Marketing.

Online solutions have been requested by our customer base, with increasing demand. Providing online solutions through our upgraded website will generate a better customer experience; improve the image of SPU within the community; and will put our customer relations par with our electric and water service standards. Additionally, there should be improved staff productivity and a reduction in manual processing.

Project Plan

Initial, high level plan to include the tasks below. Dates and dollars TBD until further development and research of project can be completed. The 2018 goal is to define the scope of the project well enough to solicit outside quotes/conversations for 2019 budget planning purposes and incorporate individual department representation. The development and testing of the new website would happen in 2019, with the launch/reveal of the new website to occur in late Q4.

1. Define project scope – meet with Utilities Manager and individual department heads to solicit input for website functionality, defining needs, wants and nice-to-haves. Present data to team to identify common goals and objectives, and prioritize these elements/features.
2. Determine scale of project – using the input from the management team, determine the impact of the scope on the budget and the timeline. Scope may need to be scaled for either, or both, of these reasons.
3. Create the framework – develop screen flow as a visual guide to designing the website's structural makeup. Is the website following the defined goals and objectives, in the best manner?
4. Research third party providers – look at pros and cons of local providers vs. regional vs. national and determine the best fit for SPU. Rank each vendor to make at an objective determination.

5. Vendor Information Meetings – identify and schedule informational presentations with select vendors. Utilize these meetings to further educate SPU staff on the website redesign process and gain insight into the vendor's abilities
6. Develop RFP – based on the required features, functionality and pages as defined by the framework, an RFP will be developed and submitted to the identified vendors. This will happen in 2018, with an effort to be completed prior to the submission of the 2019 budget. NOTE: If not completed by that date, an educated estimate will be included within the budget to ensure the project can progress in 2019.
7. Vendor Selection – based on RFP responses a third party vendor will be contracted.
8. Project Task List – identify all areas of involvement throughout the development of the website. NOTE: At this time drilling down to the actual tasks associated with each area cannot be defined. That will be a very large and complex effort driven by the project scope. This document is intended to provide a high level overview of what/who will be involved.
    a. IT (servers, hosting, security, site maintenance, interfaces, web developers, etc.);
    b. Design (color scheme, new SPU logo/branding, page design, etc.);
    c. Content development (departmental, topic-based, SPU general, etc.)
    d. Reporting/Output (internal and external requirements)
    e. External Links/Third Parties (coordination with external parties, accurate links, functionality, etc.)
    f. System testing (page flow, execution, content proofing, design consistency, output, etc.)
    g. Training/Process Flow changes (internal staff training, procedural changes due to automation, customer communications/training)
9. Project Timeline – items identified in the project task list will need to be assigned in the order the tasks need to be completed, as some tasks are dependent on the completion of others. Due dates will be assigned to each of these tasks, thus developing the complete project timeline.
10. Launch – projected to go live in Q4 2019 – unless scope is too large to accomplish this. Web developer input will be valuable to determining the feasibility of this date; their expertise in how we could scale the project and still achieve our goals and objectives, and/or "build" the website in phases to accommodate our constraints of time, money and resources.
11. Communicate – a formal marketing plan would be developed to announce and promote the new website. Type of launch communications/tactics (soft or hard) is TBD.

Ranking of Website Inclusions

Utilize a scale of 1-10, with 10 being a definite need and 1 being something that can wait/not necessary

Category	Total
Updated Design/Look	60
Improved Navigation	56
Links to External Websites	55
Website Tracking Tools	
Resolution tracking - receipt/response/resolution	39
Content approval - online review/approval	33
Website analytics	42
Online Information/Forms (viewing & downloading only)	56
Social Media	
Tweets	32
Website posts showing up on SM pages	36
Blogs	26
Customer Information	
Integrated account information, including payments	44
Outage Management/Communications	
Outage/Problem reports (postings)	59
Outage/Problem notifications (individual notifications)	29
Outage maps	33
Planned Outage notifications (postings)	51
Planned Outage notifications (individual notifications)	32
Downed Communication System notifications (postings)	48
Downed Communication System notifications (individual notifications)	27
Communication Portal (Inbound)	
Reporting Service - safety concerns, streetlight outags, power outages, water issues	59
Online Application Processs - jobs and request for service	41
Online Request for Discontinuation of Service	39
Customer feedback portal	45
Customer surveys	43
Website Hosting/Security	
Determine hosting requirements, including internal vs external site	40
Define security requirements based on website functionality/content	50
Determine content controls/updating ability	50
Determine content ownership/rights	50
Document handling	43
Determine new email domain/URL	29
Stream Commission Meeting videos	42

PROPOSAL FOR

WEBSITE DESIGN & DEVELOPMENT

SHAKOPEE PUBLIC UTILITIES

Signalfire, LLC
1711 Woolsey Street | PO Box 491
Delavan, Wisconsin 53115
(262) 725-4500 | matthew@signalfire.us
www.Signalfire.us

PROPOSAL FOR SERVICES

Submitted by:
Signalfire, LLC
Matthew B. Olson, Sole Member
1711 Woolsey Street, STE D
PO Box 491
Delavan, WI 53115

(262) 725-4500 Telephone

matthew@signalfire.us
www.signalfire.us

Objective

Signalfire, LLC (Signalfire) wishes to submit the following website design and development proposal for the Shakopee Public Utilities ("Shakopee" or "SPU") in response to to your original email of approximately October 1, 2018 and subsequent phone discussions.

What sets Signalfire apart from the competition is storytelling. One common thread between everyone at Signalfire is their passion for storytelling. The ability to communicate and engage an audience, regardless of medium, is critical for marketing and advertising in today's environment. We believe this ability to "share stories" defines how Signalfire will succeed in developing a successful, branded website experience for SPU.

Signalfire sees itself as the perfect choice for SPU as a qualified marketing vendor and full service marketing agency because:

- Signalfire provides creative / marketing services for similarly-sized community organizations and related businesses.
- **Signalfire has won multiple awards for marketing design <u>and</u> website development.**
- Signalfire possesses a qualified team of professionals passionate about innovative marketing practices involving all forms of media.
- Signalfire is a growing agency with a solid procedural foundation and inventive creative ideas that will directly benefit SPU.

Signed By:

Signalfire, LLC
Matthew B. Olson, Sole Member

TABLE OF CONTENTS

WHY SIGNALFIRE?

Shakopee Needs Branding Guides and Outfitters

Selecting Signalfire to collaborate with the wide range of stakeholders within Shakopee Public Utilities is an excellent choice. Our team of creative marketing guides and outfitters is more than just marketing shtick, it's a statement of how we work.

Guides

Just like with an expedition into the woods, the right guide makes all the difference. As your creative marketing GUIDES, our team:

- Listens to your goals to collaborate on the best destination
- Understands the strategy to plot the right path through the wilderness
- Utilizes the right equipment needed to make the time in the field fit your vision

Outfitters

The wisdom of your marketing guide is paired with innovative OUTFITTERS who will write, design, and develop the tools needed to make your brand a success. Signalfire's idea outfitters will:

- Create the right visual for your evocative brand experience
- Give a voice to your brand through focused content, images, and video
- Develop the tools needed to bring the adventure to life

Signalfire's team of creative marketing guides and outfitters will help create your brand and develop the strategy to succeed. Our track record includes successfully working with municipalities, destination marketing organizations, and a wide range of manufacturers to create impactful websites. It doesn't stop with launching the website. Signalfire is an incredible partner for developing a strategy to keep your website performing well.

AGENCY DESCRIPTION

Signalfire began in 2002 as Signalfire Productions, the business name of Matthew Olson's freelance design efforts. In 2006, Matthew launched Signalfire as a design firm for web and print. In 2008, Signalfire incorporated as Signalfire, LLC with the addition of a Project Manager as well as a network of graphic designers and website developers. Since that time, Signalfire has continued to grow.

Signalfire quickly established itself as a quality digital agency specializing in business branding, websites, and the evolving social media medium. With clients across North America (US, Canada, Mexico), Signalfire continues to be known for innovative, creative marketing ideas that integrate web with social media and email marketing.

Design Awards and Accomplishments

3x Graphic Design USA – American Graphic Design Winner (2014)

- Logo and Branding – Humane Society of Southern Wisconsin
- Website User Experience Design – Worldbuilders
- Website User Experience Design – Lower Sugar River Watershed

2x Telly Award Winner (2015)

- Lakeland Animal Shelter – Extreme Shelter Makeover Intro Video
- Lakeland Animal Shelter – Extreme Shelter Makeover Plea Video

2x Graphic Design USA – American Web Design Winner (2016)

- Website User Experience Design – Sturgeon Bay Visitor Center
- Website User Experience Design – LSM Chiropractic

Graphic Design USA – American Web Design Winner (2017)

- Website User Experience Design – Fish Creek Civic Association

Graphic Design USA – American Graphic Design Winner (2017)

- Logo and Branding – Delta Urethane

2x W3 Website Development Award (2017)

- Website User Experience Design – Sturgeon Bay Visitor Center
- Website User Experience Design – Fish Creek Civic Association

2x Graphic Design USA – American Graphic Design Winner (2018)

- Logo and Branding – Turtle Creek Nursery
- Logo and Branding – CryoCarb

Introducing Signalfire's Team

Matthew B. Olson
Lead Branding Guide and Founder

Matthew has a diverse background ranging from technical document design to commercial printing. Passionately creative, Matthew launched Signalfire, LLC in 2006 to design brand-smart websites with a fantastic user experience. An early adopter of social media and an accomplished speaker, Matthew uses his creativity and experience to develop innovative, cross-media approaches to marketing.

Matthew is the creative force behind Signalfire. Accomplished in branding and strategic planning, his eye for coming trends has led to the success of many branding and marketing campaigns.

Lisa Oren
Project Manager

Lisa oversees client relations for the majority of Signalfire's clients. Specializing in long-term campaign management and creative operations, Lisa's organization and attention to detail ensure proper execution of marketing plans. Lisa specializes in tourism. Working with numerous communities and tourism related businesses has given her a track record of success.

Bryan Giese
Project Manager

Bryan is Signalfire's Project Manager that supports a wide variety of clients with his creativity and energy. Fluent in content marketing and brand strategy, his previous experience in the health care industry gives him incredible insight. Immensely organized and detail oriented, his skill in managing projects is second to none.

Sarah Lobdell
WordPress Developer

Sarah's expertise in website development shines through as the manager of most website projects. Her knowledge of programming, content management systems, and user experience means she can talk the talk with programmers and walk the walk with creatives to ensure websites deliver results.

Jodi Heisz
Creative Director

Jodi is Signalfire's creative heart and soul. Overseeing all creatives and design work, Jodi embraces a client's brand and takes it to another level. An experienced, talented designer, her eye for effective marketing is unmatched in our area.

Heather Bentzen
Graphic Designer

Heather is a gifted graphic artist with a talent for bringing a fresh, creative perspective to all our graphic design projects. From billboards, print materials, and logos to info-graphics, web ads, or user interface design, Heather is our go-to graphic design resource.

Ian Harris
Content Strategist

Ian sees content in the big picture of search engine optimization, social media, and email marketing. He specializes in content development, email marketing strategy, social media management, and implementing web marketing strategies. Detailed and meticulous, Ian ensures web content performs at its best in many different mediums.

SERVICE OVERVIEW AND EXPERIENCE

About Our Branding

Whether you're a fresh startup, an established corporation, or a destination marketing organization, branding is what defines your business or organization to the world. Signalfire provides comprehensive services ranging from logo design to strategic consulting. Our process of listening and assessing has been proven successful time and time again.

When working with Signalfire, you have a trusted partner who is intimately familiar with your brand and your long term goals.

About Our Graphic Design

Creative, effective graphic design is one of the mainstays of Signalfire's services. Designing for print or web, the creativity, vision, and brand awareness our team brings is second to none. Our design teams understand the various mediums of design and the different ways audiences respond to a billboard on the highway versus a banner ad on a news website.

Signalfire takes pride in understanding the mission, the marketing, and the message your business's design must deliver.

About Our Website Design and Development

Like it or not, we live in a web-powered world. From mobile devices to our televisions, the web has become one with nearly every aspect of our lives. Developing the right presence on the web that targets, engages, and retains your audience makes your website far more than a simple online brochure. Signalfire's web team is an incredible mix of user experience designers, standards-wise programmers, and search smart content managers.

Key to your business's success is our listening and assessment process. We spend the time in advance to learn your needs, learn your industry, and learn what will make your audience respond. When creative work begins on your website, defined goals and standards will keep the project moving crisply towards success.

Critical to our success is a simple statement: By the time your project is complete, you'll understand your website as well as we do.

Signalfire's expertise in user experience, planning, and execution is evident in every project we complete. An extensive list of websites can be provided upon request.

About Our Social Media

It isn't 2012 anymore, and what was once clever is now expected. Consumers are expecting a Facebook page to spot deals, a Twitter account to listen for insider news, a YouTube channel to watch videos, to share or exchange ideas over Pinterest, a presence on LinkedIn to engage business-related questions, and even to snap a selfie on Instagram. Signalfire has been heavily engaged on social media since 2008. We understand exactly how quickly things change and where the trends are going.

Signalfire can provide monitoring or listening services, platform-smart postings, useful reporting tools, and expert insight into which social media platforms will work best for your business or organization.

Signalfire continues to push the leading edge of social media use and integration with innovative approaches to events and communities.

About Our Content Services

A common expression small business owners often hear is, "Content is king," but few designers or developers say why. Simply put, content is the life blood of your brand presence. From your website, search engines, newsletters, email marketing, social media, ads, and brochures—all of it depends on medium-smart, effective content.

Signalfire can offer a selection of services surrounding content strategy, content marketing, and content development. We can assist in the development of an ongoing strategy that maximizes your team's knowledge of online resources of a website or blog. From identifying topics, planning a calendar, to writing the content itself, Signalfire provides a comprehensive service profile in this too-often overlooked marketing category.

Signalfire's process in content development allows us to provide insightful, beneficial content from event descriptions to technical articles. A key metric for our content's success: Write once and use over and over again.

About Our Email Marketing

There is a battle over your inbox, and SPU wants a strategic partner such as Signalfire to win the fight. Signalfire provides creative design services to develop an email marketing template that fits your brand and your message. We take into consideration mobile friendly layouts, CAN SPAM or CASL compliance, strong image use, and the ever-critical subject line message. The end result is a platform to maintain a strong top-of-mind position with your target audience.

Signalfire provides the right tools, the right tracking metrics, the right content, and the right methodology to deliver successful email marketing campaigns.

About Our Photography

Visuals are everything in tourism. Signalfire maintains a fantastic relationship with a significant number of photographers. We frequently assign our imagery team to capture critical shots at critical times. Our photographers utilize the best gear, the best practices, and frequently deliver "that" shot. We strongly recommend using original imagery to capture the most authentic experience possible.

Signalfire can schedule, coordinate, and arrange photographers, models, and staging. Whether we're capturing events or staging a cover shoot, Signalfire delivers only the best images.

About Our Video Production

There is a strong bond made between the viewer and the brand during a video. Eye contact, voice, and a perceived relationship makes video one of the most powerful mediums a brand can employ. Signalfire utilizes a variety of videographers for videography but applies our trademark creativity and inventiveness to bring your brand story to life. Our role as planners, producers, and directors ensure that the brand vision shines through.

Signalfire's experience is highlighted with **two Telly Awards**, over a dozen produced videos, and countless social videos. Our team has the story and the experience for bringing your brand to life.

SUCCESS STORIES

NBW Bank – Regional Bank in Central Wisconsin

www.nbwbank.com

The National Bank of Waupun engaged Signalfire to develop an entire new branding and marketing effort for the 100+ year old financial institution. Signalfire continues as the Agency of Record for NBW by providing services ranging from website support to creative marketing.

- Renaming, logo design, and branding
- Creative redesign of all brand identity materials including stationery, envelopes, statements, and advertising
- Graphic design for mobile banking app
- Comprehensive website development using WordPress
- Feature-rich website with easy administration and content management
- Website content writing within compliance for financial institutions
- Email newsletter platform
- Implemented a social media plan including account setup and integration with compliane monitoring platform
- Ongoing marketing support including annual marketing plans, brand management, social media monitoring, and campaigns
- Comprehensive customer service survey utilizing online and print tools, data collection, and conclusive report

Village of Fontana – Mixed Use Municipal & Tourism

www.villageoffontana.com

Fontana-on-Geneva-Lake is a vacation home haven in the Lake Geneva region of Wisconsin. The community needed to build a website presence that could handle the municipal government requirements as well as feature the community as a wonderful getaway destination.

- Mobile responsive WordPress website development
- Feature-rich website with easy administration and content management
- Searchable business directory
- Individual municipal department pages
- Extensive library of Village Board and committee meeting minutes, agendas, and information packet to satisfy state open records requirements
- Agenda-style calendar with municipal and community event listings
- Online payment gateway for municipal bill payment
- Multiple blog channels for local news, local event details, municipal updates

Fish Creek Civic Association

www.visitfishcreek.com

Contact: Denise Stillman, Board President – (920) 495-1151

Fish Creek Civic Association oversees the promotion of Door County's cultural heart. Signalfire has provided extensive creative services since 2015. Some of these services include:

- **Two-time award winning website development (GD USA – American Web Design Award 2017, W3 Award 2017)**
- Annual 48+ page activity guide design and production (since 2015)
- Content planning, writing, and management
- Advertising design, event promotion design
- Print management
- Promotional marketing materials
- Email marketing
- Custom illustrated map of downtown section and surrounding area used in print materials

Sturgeon Bay Visitor Center

www.sturgeonbay.net

Contact: Pam Seiler, Executive Director – (920) 743-6246

Sturgeon Bay is the largest city in Door County with a thriving tourism culture. Signalfire has been the organization's agency of record since 2006 with responsibilities in print and web.

- Custom developed website and member management platform
- **Two-time award winning website development (GD USA – American Web Design Award 2016, W3 Award 2017)**
- Annual 48+ page activity guide publication since 2006
- Managed social media 2008 – 2012, consulting and advising 2012 – present
- Advertising design, event promotion design
- Print management
- Content calendar development
- Comprehensive email marketing planning and execution
- Custom illustrated map of city used in print materials
- Website maintenance including content updates and SEO

Other Projects:

Walworth County Economic Development Alliance

Website - www.walworthbusiness.com

Best Events Catering

Website - www.besteventscatering.com

PROJECT SUMMARY

Signalfire seeks to construct a mobile-responsive website for Shakopee Public Utilities to utilize as a resource for the 17,000+ municipal customers in their care. The new website will have several key goals:

- Be a usable, reliable resource for critical information ranging from outage notifications to connect/disconnect requests
- Provide a helpful customer service touchpoint that offers information about billing, communications, and community engagement
- Be a communication conduit with the wider community including businesses and government entities for assistance in areas such as economic development, business relations, and community building

The completed website will be the primary touchpoint for SPU's marketing and communication with the community. Supporting touchpoints include social media, email newsletters, urgent email communications to easily connect customers with SPU.

Signalfire specializes in support beyond the website launch. Our team of content marketing experts can provide support with:

- Website support with maintenance and content updates
- Search engine optimization (SEO)
- Content planning, editorial calendars, and keyword research
- Content writing, optimizing, and distribution
- Email newsletters – planning, scheduling, list management, and list building
- Social media strategy, planning, monitoring, and direct management
- Online reputation management with Google My Business, Google reviews, social media reviews, and more

Our team looks forward to developing an incredible website and being a valuable resource to SPU in the future.

Project Timeline

The dates listed below are approximations. Final dates will be set with the approval of the contract and delivery of key milestones.

Notification of Contract Award

Creative kickoff meeting or webinar .... Notification + 2 weeks

Create website site map and content roadmap

Receive website content and images from SPU

Review website content for spelling, grammar, and images then submit to SPU for approval

Website style guide and wireframe design submitted to SPU .... Kickoff Meeting + 2 weeks

Signed Approval of Website Content / Wireframes

Commence design of website creative mockups

Deliver two (2) creative concept mockups .... Approval + 4 weeks

Creative mockup revisions and selection of design

Signed Approval of Prototypes

Install WordPress and website buildout

Content migration and formatting

Development Link Ready For Review.............. Approval + 8 weeks

Revisions, review, and testing of website....... Link Delivery + 4 weeks

24 WEEKS

Signed Go-Live Approval

Target launch .... Go-Live + 1 week

Training webinar................................ Go-Live + 3 weeks

Creative Kickoff And Site Map

The process will begin with a Creative Kickoff meeting or webinar in which SPU and Signalfire will review the needs and structure of the planned website. The outcome of the meeting will give the Signalfire creative team a clear vision of the desired website.

The second major outcome of the meeting will be the creation of the site map or a list of pages to be displayed on the website. A site map will allow Signalfire to plan for site design, navigation architecture, and image management. The list of pages will also guide SPU in the delivery of content.

SPU must approve a site map prior to the next stage.

Content First

The approved site map will outline all content deliverables required for Signalfire to commence work on the development of the website. In order to deliver the needed website text and images, SPU will do one of the three (or a mix):

- Provide Signalfire with all page text, images, or other needed materials
- Migrate website content from existing website (original images may be required)
- Request a quote from Signalfire to write or develop new content for the website

Once all content is provided, Signalfire will review all content for grammar, spelling, and recommended length. Signalfire will present the reviewed content to SPU.

SPU must approve the content prior to the next stage.

Wireframe Design

Working together, Signalfire and SPU will select a base framework for custom design and functionality modifications. From this discussion, Signalfire will provide SPU with a branded style sheet indicating colors, fonts, text styles, and logo usage. Additionally, Signalfire will provide wireframe layouts of the homepage and six (6) page styles in both desktop and mobile formats.

SPU must approve the wireframe and style sheet prior to the next stage.

Website Design Mockups

Signalfire will build on the approved wireframe concepts and style guide to design two (2) mockups consisting of a homepage design and a child page design.

Based off these two (2) designs, SPU will make up to two (2) rounds of recommendations and revisions, ultimately selecting one (1) design for the detailed mockups.

Additional revisions beyond two (2) rounds will be billed at $125 per hour with a one (1) hour minimum. Additional Initial Mockup designs may be requested at $1,500 per design iteration.

Initial mockups will be delivered as non-functioning JPGs or PDFs.

Website Buildout

Signalfire will commence building the website based on the wireframes with the approved site map, website style guide, and website content. This "build out" process will also construct the needed functionality for the website including:

- Installation and setup of WordPress
- Application of the approved design
- Construction of site architecture per the site map
- Migration of approved text, images, and other content
- Implementation of functionality outlined below

Description of Functionality

- Website development for www.spucweb.com
- WordPress content management system that allows for easy updating of content, images, and products as well as adding new pages to the website
- Mobile responsive design for optimal display on tablets and smartphones
- Creation of a focused user experience intended to showcase SPU's services, be a touchpoint for customer service, and be an informational resource for the community
- Dynamic and mobile-friendly homepage experience that clicks through to destination landing pages with options for a homepage video header
- Thoughtful navigation plan that allows for future expansion that will not diminish the design
- Clear and mobile-friendly contact information, including email address and telephone number
- Site-wide "notification banner" to display critical messaging such as outage notifications
- Installation of search engine optimization plugins
- Technical SEO review and implementation of recommended features including installation and setup of Google Analytics, Google Search Console, and other traffic or performance monitoring tools
- Email newsletter signup integrating into existing system
- Social media links
- Online forms delivered via email to defined SPU team members including:
    - General contact
    - Report an outage

    - Application for employment
    - Service connect / service disconnect
- Ability to embed video in primary content areas
- Embedded Google map showing service area
- Multiple blog channels for news, FAQ, employment listings, rebate news, meetings, etc.
- Event calendar with event-specific pages for event details
- Online payment gateway link to Paymentus system
- Document repository structure for storing and organizing numerous PDFs or similar web-ready documents such as Terms and Conditions, rules and regulations, varoius applications, ACH forms, etc.
- Password-protected login area for documents, pages, or forms includes a single user name / password (helps in troubleshooting with members who forget their passwords)
- Telephone, email, and webinar administrative support for three (3) months from date of launch
- Website training on features and functions (typically 1 – 2 hours)

** Homepage video can impact several elements of user experience. Video may not auto-run on mobile devices. Video will also increase pageload times that possibly impacts search engine performance.*

Go-Live Process

With the written approval of the developmental website, Signalfire will commence the launch of the website. While we attempt to make the launch process as smooth as possible, potential snags and pitfalls can happen. We plan the Go Live process during off-peak days and times in case there are service interruptions.

The "Go Live" process involves:

- Scheduling a launch time to minimize SPU's traffic impact
- Conduct a backup of existing website and developmental website
- Confirm access to DNS records and domain name information
- Migrating or transitioning the development site to the final server
- Redirection of DNS (changes may take up to 72 hours to take effect)
- Installation and configuration of SSL
- Confirm transition or installation of Google Analytics and Search Council
- Installation and configuration of HotJar user experience tracking
- Confirmation of site launch with device, platform, and browser checks

WordPress Training (Post-Launch)

We don't toss you the keys and wave "good luck."

Once the website has launched, Signalfire schedules the training session or webinar. This one (1) to two (2) hour training session covers the basics as well as the details surrounding the website. Our goal is to have you be as fluent with the website's operation as we are. Training can occur either in person or via webinar. Training webinars may be recorded for later use.

After the training, Signalfire provides a high-level reference manual related to maintaining the website. This document will give you the basics or a quick refresher.

Hosting and Maintenance

Signalfire will provide comprehensive website hosting services for your website. Our managed servers are housed with a national level hosting provider with secure locations in several US states. Included with Signalfire's hosting services:

- 24-hour technical support from hosting facilitator
- Service monitoring
- Daily website database backups with one click restore
- Available Content Distribution Network (CDN) services
- SSL Security Certificate

Signalfire also provides critical website maintenance in order to keep the site running in tip-top shape. These maintenance efforts will ensure both the core WordPress software and critical plugins remain up to date and functioning.

- Core WordPress software updates
- Plugin updates and testing to ensure compatibility
- Confirmation of backups

Content Update Support (Optional)

Signalfire can provide ongoing site maintenance and assistance with content updates. Updates include any content, events, images, video, or any other non-development updates to the website. These services are for 12-month periods and billed with hosting services.

Signalfire recommends providing up to three (3) hours per month of content support. This support includes image updates, content updates, or other non-developmental website updates. Three (3) hours equates to approximately four (4) updates similar to blog entries, event entries, or other article additions.

Additional content update support is an optional service that begins at $350 per month for three (3) hours.

BUDGET

The following pricing is based on current specifications.

Website Design and Development .... $ 16,250

Website Hosting & Maintenance .... $ 150 per month

Website Development	**$ 16,250**

Optional Budget Items

These are commonly added services to our website developments.

Website Updates (Optional) .... $ 350 per month

Content Development / Website Copywriting .... $ 150 per page

INTENT TO PROCEED

Change Orders

No surprises. Ever.

Any additional billable time, materials, or other costs will be presented to SPU in a written change order **prior** to any billable actions being accrued. This written change order will indicate exact costs and impacts to delivery timeline.

Terms

Payment will be made in US Dollars in the form of business check or cashier's check. All invoices are due on receipt. A deposit of 50% ($8,125) will be due at the approval of this agreement. Balance will be due at the launch of the website.

Signatures

Based on the descriptions of service, the Shakopee Public Utilities would like to proceed with Signalfire, LLC.

Name *Printed Name* *Date*

TERMS AND CONDITIONS

Expiration of Estimate

This estimate of costs and services is valid for up to thirty (30) calendar days unless otherwise indicated in writing. After the expiration of this estimate, a new estimate may be requested.

All print material estimates expire after thirty (30) days. Print estimates are based on specific characteristics of the project. Changes to specifications including, but not limited to, produced quantity, paper properties, production methods, and/or finishing characteristics will require a new estimate for cost and time.

Change Orders

Any changes to project specifications, deliverable services, or physical deliverables that impact the cost of the project will require a written change order to be approved and signed by the Client. The change order will include an updated budget and deliverable timeline. No additional billable time or services will be accrued without written approval.

> NOTE: Revisions to creative design projects or copywriting: Creative design and writing services pricing estimates include two (2) revisions delivered to the Client past the first concept or draft. Design or writing time accrued past two (2) revisions will be billed at an hourly rate of $120 per hour with a one (1) hour minimum. Revisions will not exceed four (4) hours without written authorization.

Project Termination

Both Signalfire and the Client reserve the right to terminate the project or agreement with written notice to the other party. Once written notice is received all billable work will cease. A final invoice will be delivered based on completed work at the time of the notice minus any deposit. Monthly deliverables will be pro-rated based on the date or percentage of delivery.

Website projects involving a deposit that are terminated prior to the approval of creative designs or selection of a development template shall be considered compensation for completed work. Once the Client approves the creatives or selection of a development template, additional time will be billed based off an estimate completion of the project.

Dormant Project Termination

If the Client fails to communicate in a professional or timely manner, Signalfire reserves the right to terminate the project after thirty (30) calendar days of non-communication. Non-communication by the Client shall include unreturned phone calls, no response to emails, and/or failure to deliver essential materials for the completion of the project. Examples of essential materials include, but are not limited to: text, images, branding assets, security credentials, or other materials essential for the completion of the project.

Dormant projects will be invoiced based on the work completed. Once a project is dormant, a Client may restore the project with a $250 reinstatement fee due prior to the commencement of additional work.

Ownership of Materials

All project materials including, but not limited to, intellectual property materials, designs, concepts, processes, and materials are the sole property of Signalfire, LLC until such time as the materials are paid in full. Signalfire reserves all rights until full payment is made at which time Signalfire shall transfer ownership to the Client. Once materials have been paid in full, the Client reserves full rights and ownership to the materials.

Payment Terms and Conditions

All invoice payments are due upon receipt or on the agreed schedule. Payments shall be made in US Dollars by cash, check, money order, or cashier's check. Checks returned or rejected by Signalfire's financial institution will be assessed a $50 fee.

Invoices outstanding past sixty (60) days will be subject to a $25 late fee. 1.5% of the invoice will be added every thirty (30) days past the initial sixty (60) day fee. Invoices remaining past 120 days will be sent to collections.

SPUC -- CORE COMPETENCIES & SUCCESSION PLANNING TIMELINE

Project 1: Core Competencies

Project 2: Succession Planning Process

John Crooks retires

Preapproval	Admin. Prep.	Est. Social Arch.	Interview Prep	Interviews	Selection / Admin.	Overlap
Objectives	Construct Core Comp's Micro Map	Final Approvals	Interview Invitations Forms / Grids	Setting	Offer Negotiations Acceptance	With John C.
Scope		Communicate		Schedules		"On Boarding"
Macro Map	Timeline	Apply Core Comp - Prof. Devel. - Talent Review	"Sign Off" letter	Discussion & Decision	Feedback to all	Exec. Assimilation
Overview	Commun. Plan		Selection Team - Determined - Trained		Binder	Early Feedback
Inputs - Process - Content	Calendar	Gap Analysis For Directors				
		Revise Doc's Binder	Select Search Firm		*New Hire starts*	
Est. Investment: $1,000	$3,000	$4,000	$5,000	$2,000	$2,000	Project 3 - TBD

File: SPUC Timeline v2 8.2.18

SPU Communications/PR Plan

The following communications plan is intended to be a roadmap for SPU as we convey information about our organization and culture, respond to customer interests and concerns, and share our accomplishments with the Shakopee community.

Purpose/Goal:

- Foster a positive relationship/partnership between SPU and the Shakopee community
- Communicate with the Shakopee community more frequently and more openly
- Increase public knowledge and a greater understanding of SPU and its practices
- Promote the positive aspects of a municipal utility and SPU's role in the community

Target Audiences:

- Ratepayers
    - Residential Customers
    - Non-Residential Customers
    - Key Accounts
- Public Offices
    - City of Shakopee – Staff and City Council
    - Chamber of Commerce
    - Scott County Staff
- Developers

Message:

What is our message? What content will appeal to what groups? What style do we want to utilize with our audiences? The answers to these questions will drive the content that appears in print, social media and in-person conversations. It will also drive what medias we use and for which audiences.

Communication Media/Channels:

We also have to think about how we will deliver the message. Not everyone reads postal mail. Some customers aren't on facebook. Who still reads the newspaper? Would a text reach more people than an email? Blogs? Inserts? Website content? These are all questions we have to consider as we look at the demographics of our service territory.

Do we need to consider language? Not in choice of words or style, but in actual language – English vs. Russian? Somali? Spanish? We can't assume English will reach 100% of our audience, but we need to determine the extent we will go to in presenting information in other languages.

Resources:

Staffing needs to be considered as we create this communications plan. To create the plan and then be unable to execute is an exercise in futility. Currently, we are not staffed to draft newsletters, write blogs, submit press releases, post and/or monitor social media daily or with any consistency.

Should we want to increase our mailing inserts or run more ads in magazines or the local newspaper, or create professional packets for developers, increased design and print dollars will be required.

The utilization of outside sources, such as a PR firm or a web developer, should be considered as well.

We need to identify all resources, staffing or otherwise, that are required to follow the communications plan and then we need to commit budget dollars to those resources.

To move forward with this communications plan, we could execute in phases, utilizing what dollars have been included in the 2019 budget and then planning for 2020 and future budgets.

Action Plan:

A project plan will need to be written identifying the individual elements of the communications plan and a corresponding timeline for each element. Annually a communications plan should be developed outlining the community events, customer visits, written communications, social media touches and/or web content to ensure the consistent, ongoing message we want to convey. This message/action can and should vary by year to address the current opportunities and/or issues facing SPU.

Evaluation:

The last piece of the communications plan should be an evaluation of the goals and purpose stated. Have we made progress? Are we communicating in the best manner? A baseline may or may not be established at the start of the plan, but in either case feedback from our targeted audiences is critical to the success of the plan. Dollars should be budgeted for this evaluation as well.

Why are water utility costs are higher for new developers in Shakopee than surrounding areas?

Shakopee isn't like (Doesn't look like?) many of our closest neighbors.

1. Shakopee has a unique geographical footprint. First, we're a valley and a lot of expansion is happening to the south, which is uphill. Water doesn't flow uphill on its own so ... Secondly, a large portion of our city sits on bedrock and xxxxxxx. These surfaces are difficult to dig in so additional costs are associated with development in certain areas. Some customers may remember the dynamiting that was required to build Amazon. Another factor is the topography that limits us from where we can drill wells. We utilize booster stations and holding tanks in those areas where we cannot drill locally.
2. Shakopee is growing and our infrastructure is still being developed. Some of the areas we are compared to are fully built and costs are contained to ongoing maintenance, which we have in addition to new system developments. Some cities have no infrastructure because they purchase their water. Infrastructure expense does not come into play for these cities.

Could these costs be distributed so it isn't cost prohibitive for a single developer to bring new business to Shakopee?

SPU has a blended system where all unique variables are considered.

1. SPU looks at our system requirements as a whole (bedrock, limestone, pressure zone 2?, etc) and fees are based on that. The costs are the same for all developers, regardless of where they are developing in our service territory. If we didn't do it that way, developers on the east side of Shakopee could be paying xx times the amount a developer on the west side of Shakopee because of the xxxxxxx that is unique to eastern Shakopee. Or, someone developing in south Shakopee would need to pay for a well if we hadn't planned for the development and built a holding tank? Booster station?

What exactly do these water fees pay for when a developer comes to Shakopee?

Think Pipes. Think Infrastructure. Think Future.

Trunk Water Charge (TWC) – this fee is calculated on the size of the land area that is being developed and contributes to a fund that is used specifically for system expansion related to piping. Sometimes larger pipes are required to support the needs of a development, or what lies on either side of a particular development, and oversizing is required. Those expenses would come out of this fund as well.

The TWC fee is calculated on the gross land acreage minus any deeded right-of-ways, wetlands or parks. So, net acreage x the established fee = the TWC for a particular new development.

Water Capacity Charge (WCC) – this fee is based on what will be built on the land or how water will be used with this development. A restaurant vs a warehouse vs a residential neighborhood will use water differently and will have different water "capacity" requirements.

Our WCC is based on the equivalent number of SAC (Sewer Access Charge) units established by The Met Council. The more SAC units established, the more capacity required of our water system. Units x the established fee = WCC.

This fee contributes to the fund that is required for the growing infrastructure as discussed above. It funds the building of booster stations, storage/holding tanks, the drilling of wells, possible treatment plants, etc.

It is *not* the cost to connect new development to the pipes already in the ground, which the previous term "Water Connection Charge" may have inferred. It really is about the capacity impact on the system.

Why do developers have to be the ones to pay these charges?

It is a philosophy adopted by the Shakopee Public Utilities Commission xx years ago so the expense is not born by SPU ratepayers.

Simply stated, there is a cost associated with infrastructure and expansion, and it has to be paid for by someone. In 19xx, the Commission decided via resolution that expansion expenses would be paid for by new developers at the time of development – not in advance of it – and the cost of future expansion would not be paid for by the rate payers – residential or non-residential.

If the Commission were to change this philosophy midstream, before Shakopee's water system is fully built, it would mean those developers who have already paid for their own development would now need to fund the future development of others through higher water rates on their monthly bills. Residential water rates would need to increase as well.

The good news in all of this is that SPU's water rates are in the lowest one third among metro water rate payers, and the advantage of developing in Shakopee is long-term, lower water rates.