BEFORE THE STATE CORPORATION COMMISSION

OF THE STATE OF KANSAS

In the Matter of the Joint Application of Sunflower Electric Power Corporation, Prairie Land Electric Cooperative, Inc., The Victory Electric Cooperative Association, Inc., and Western Electric Cooperative Association, Inc., For Approval of Continuation of 34.5 kV Formula-Based Rates and Updated 34.5 kV Loss Factors	**Docket No.** 21-SEPE-019-TAR

PREFILED DIRECT TESTIMONY AND EXHIBITS

OF

ERIK SIGURD SONJU, P.E.

ON BEHALF OF

JOINT APPLICANTS

July29, 2020

PREFILED DIRECT TESTIMONY AND EXHIBITS
OF
ERIK SIGURD SONJU, P.E.

ON BEHALF OF
JOINT APPLICANTS

I. QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Erik Sigurd Sonju.

Q. By whom are you employed and what is your business address?

A. I am employed by Power System Engineering, Inc. ("PSE"). My business address is 1532 W. Broadway, Madison, Wisconsin, 53713.

Q. What is your present position at PSE.

A. I am the President of PSE as well as the Vice President of our Utility System Planning and Studies department.

Q. Please describe PSE.

A. PSE is a consulting firm serving electric utilities, independent power producers, renewable energy developers, and industrial companies across the country. Our headquarters is in Madison, Wisconsin with regional offices across the Midwest including Topeka, Kansas. Within the power industry, PSE provides professional services in the areas of power supply planning, transmission and distribution system planning, transmission and distribution infrastructure design, technical operations support, load forecasting, retail and wholesale rate, and cost of service studies.

Q. What is your educational background?

A. I graduated from North Dakota State University in Fargo, North Dakota in 1997 with a Bachelor of Science in Electrical Engineering, which included an emphasis in Electric Power Systems. I completed the Robert I. Kabat Management Internship Program at The University of Nebraska, Lincoln in 2006.

Q. What is your professional background?

A. From 1997 to 1999, I was employed with Great River Energy as a Planning Engineer. My work responsibilities primarily focused on long-range and short-range system planning studies, system sectionalizing studies, and power quality investigations.

From 1999 to 2001 I was employed with Heartland Engineering Services as a System Engineer. My work responsibilities included long-range and short-range system planning studies, system sectionalizing studies, line design, substation project management, power quality investigations, cost of service studies, rate studies and capital credit allocation studies.

From 2001 to 2006, I was employed with Great Lakes Energy and held the title of System Engineer. As System Engineer, I managed the engineering and system technology departments for the distribution cooperative. My work responsibilities included the standardization of engineering, operation, and construction practices for the newly merged cooperative. Other responsibilities included the development and follow through of construction work plans, system reliability initiatives, distributed generation interconnection standards and day-to-day operation of the distribution system.

I joined PSE in 2006 as a Leader of System Planning and eventually became responsible for leading other practice areas of the firm including electric utility infrastructure design, technical operations support, energy resource planning and design, load forecasting, utility performance benchmarking and industrial engineering. I became President of PSE in 2018.

My areas of expertise included transmission and distribution planning studies, transmission and distribution line design, distributed energy resource interconnection studies, and a range of other studies and designs that require complex engineering. I also provide training to electric utilities in the subject matters of line design, system planning, system protection and distributed energy resources.

I am a Professional Engineer in 20 states, including Kansas. I have attached a copy of my current curriculum vitae as Exhibit ESS-1.

Q. Have you previously presented testimony before the Kansas Corporation Commission ("KCC" or "Commission")?

A. Yes. I have provided written and oral testimony before the KCC on two separate occasions. The first occasion was on behalf of Sunflower Electric Power Corporation ("Sunflower") in Docket No. 09-MKEE-969-RTS in the matter of the application of Mid-Kansas Electric Company, LLC for approval to make certain change in its charges for electric service. The second occasion was on behalf of Southern Pioneer Electric Company in Docket No. 18-KPPE-343-COC in the matter of the application of Kansas Power Pool for certificate of convenience and authority to transact the business of an electric utility in the state of Kansas for transmission rights only to cross service territory of Southern Pioneer Electric Company and Ninnescah Rural Electric Cooperative.

II. INTRODUCTION

Q. On whose behalf are you presenting testimony?

A. I am presenting testimony on behalf of the Joint Applicants.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to present the results of an engineering study conducted by PSE which modeled and calculated the losses of the former Mid-Kansas Electric Company, Inc. 34.5 kV system for the purpose of developing updated loss factors to be used in the Sunflower Member's Local Access Delivery Service ("LADS") tariffs.

Q. Are you sponsoring any exhibits with your rebuttal testimony?

A. Yes. As supporting documentation to my direct testimony, I am sponsoring four exhibits. These exhibits include:

- ❑ <u>Exhibit ESS-1</u>: My curriculum vitae
- ❑ <u>Exhibit ESS-2</u>: MKEC 34.5 kV System Loss Analysis – Prairie Land Electric Cooperative, Inc.
- ❑ <u>Exhibit ESS-3</u>: MKEC 34.5 kV System Loss Analysis – The Victory Electric Cooperative Association, Inc.
- ❑ <u>Exhibit ESS-4</u>: MKEC 34.5 kV System Loss Analysis – Western Cooperative Electric Association, Inc.

Q. Were these Exhibits prepared by you or under your direct supervision?

A. All Exhibits were prepared by me or under my direct supervision

Q. **Do you have specific professional experience related to the testimony you are providing to the KCC?**

A. Yes. Over the last twenty years of my profession, I have studied or directed the study of over 50 electric utility systems. Through the course of these studies, I have made thousands of calculations related to system load, capacity, voltage, and losses. More specifically, I first studied the system losses of the Mid-Kansas Electric Company, LLC 34.5 kV in 2009 which loss factors were developed and submitted to the Commission for tariff approval under Docket No. 09-MKEE-969-RTS. This is the same 34.5 kV system that is now owned by the Sunflower Members. More recently, I oversaw a similar study of the same 34.5 kV system for the development of updated loss factors that are being submitted in this joint filing.

III. DIRECT TESTIMONY

Q. What do you wish to present to the Commission on behalf of Sunflower?

A. I wish to present updated loss factors to be applied to the LADS tariffs addressed in this joint filing which are supported by three separate reports attached hereto as Exhibit ESS-2, Exhibit ESS-3, and Exhibit ESS-4.

Q. What updated loss factors are you presenting to be applied to the LADS tariffs addressed in this joint filing?

A. The LADS tariff applies an energy loss factor which has been recently updated in a 34.5 kV system loss study completed by PSE. The updated loss factors for the 34.5 kV systems owned by Prairie Land Electric Cooperative, Inc., The Victory Electric Cooperative Association, Inc., and Western Cooperative Electric Association, Inc. are summarized in the following table.

Sunflower Member System	Updated 34.5 kV Energy Loss Factor
Prairie Land Electric Cooperative, Inc.	2.33%
The Victory Electric Cooperative Association, Inc.	1.76%
Western Cooperative Electric Association, Inc.	2.50%

Q. How do the attached Exhibits support the presented loss factors?

A. The attached Exhibits present the reports of the 34.5 kV system loss studies, for each respective system of the joint filers, performed by PSE. The presented energy loss factor comes directly from these reports. Each report provides a background, methods and assumptions, data used, and conclusions.

Q. Does this conclude your testimony?

A. Yes.

VERIFICATION

I, Erik S. Sonju, of lawful age, state:

That I am the President and Vice President of Utility System Planning and Studies for Power System Engineering, Inc.; that I do solemnly, sincerely, and truly declare and affirm that I have read this Prefiled Direct Testimony and know the contents thereof; and, that the facts therein are true and correct to the best of my knowledge, information, and belief, and I affirm this under the pains and penalties of perjury.

Erik S. Sonju

Erik S. Sonju

ERIK S. SONJU, P.E.
PRESIDENT

SUMMARY OF EXPERIENCE AND EXPERTISE

- Consultant in the electric utility sector helping clients analyze and develop strategic decisions around industry best practices, policies, standards, and contracts.
- Principal engineer for electric power system studies and design projects.
- Instructor for professional development courses.
- Expert witness in regulatory hearings and civil trials.
- Licensed Professional Engineer in 20 states.

PROFESSIONAL EXPERIENCE

Power System Engineering, Inc. – Madison, WI (2006-present)

President (2018-present)

Active consultant to PSE clients in areas of expertise. Responsible for the day-to-day operations of PSE.

Executive Vice President (2017-2018)

Executive for PSE business operations and active consultant to PSE clients.

Vice President – Power Delivery Planning and Design (2010 - 2017)

Responsible for PSE's efforts in electric transmission and distribution studies and planning, substation design, transmission line design and distribution line design. Other responsibilities include overseeing system protection and coordination studies, system operations and maintenance support, distributed energy resource studies and design, and specialty studies of electric power systems.

Leader of System Planning and Line Design (2008 – 2010)

Senior engineer and leader of system planning and line design. Emphasis included short range and long-range system planning studies, distributed generation system impact studies, system protection studies, and expert testimony in regulatory proceedings associated with engineering analysis used for State Commission and FERC filed tariffs. Other responsibilities included distribution and transmission line design.

Leader of System Planning (2006 – 2008)

Senior engineer and leader of distribution system planning projects.

Great Lakes Energy – Boyne City, MI (2001-2006)

System Engineer and Manager of Engineering

Heartland Engineering Services – Rockford, MN (1999-2001)

System Engineer

United Services Group – Elk River, MN (1997-1999)

Planning Engineer

EDUCATION

North Dakota State University, Fargo, ND
Bachelor of Science in Electrical Engineering with Emphasis in Power Systems, 1997

University of Nebraska, Lincoln, NE
NRECA Management Internship Program, 2006

Numerous technical and business continuing education courses focusing on issues and topics within the power industry.

TRAINING SEMINARS AND CONFERENCE PRESENTATIONS

- Instructor for professional development courses in the areas of:
  - Distribution System Planning
  - Distribution System Protection and Sectionalizing
  - Power Quality
  - Electric Power Line Design
  - Post Construction Inspections
- Industry conference presentations on:
  - Distribution Independent System Operators
  - Distributed Energy Resource Interconnection and Integration
  - Aging Electric Utility Infrastructure
  - Economic Conductor Analysis
  - Mechanical Loading of Overhead Electrical Equipment on Wood Poles
  - Application of Series Capacitors on Distribution Systems
  - Application of Shunt Reactors on Distribution Systems
  - Impact of Electric Motors, Drives, and Phase Converters on Distribution Systems
  - Substation Protection Considerations
  - National Electric Safety Code Rules and Requirements Pertaining to Communication Attachments on Power Supply Structures.

STATES LICENSED AS PROFESSIONAL ENGINEER

Arizona	Indiana	Montana	South Dakota
Arkansas	Iowa	Nebraska	Texas
Colorado	Kansas	New Hampshire	Virginia
Florida	Michigan	New Mexico	Wisconsin
Illinois	Minnesota	Ohio	Wyoming

EXPERT WITNESS AND TESTIMONY

Utility/ Entity	Jurisdiction Body	Case No.	Description	Year
Chippewa Valley Electric Cooperative	State of Wisconsin Circuit Court, Branch 2, Chippewa County	18-CV-223	Industry expert on behalf of Chippewa Valley in the matter of stray voltage lawsuit. Presented oral testimony on specific evidence related to conditions of an overhead conductor splice and radio noise measurements by opposing expert.	2019-2020
Toronto Hydro-Electric System Limited	Ontario Energy Board	EB-2018-0165	Industry expert on behalf of Toronto Hydro. Developed filed report regarding external variables influencing the cost of electric distribution infrastructure required to serve urban core areas.	2018-2019
Southern Pioneer Electric Company	Kansas Corporation Commission	19-KPPE-343-COC	Industry expert on behalf of Southern Pioneer relating to industry standards in the planning of electric utility infrastructure. Included prefiled direct and oral testimony.	2018
Gulf Power Company	Circuit Court of the First Judicial Circuit in and for Okaloosa County, Florida	2017-CA-000709	Industry expert on behalf of defendant in the matter of overhead power line structural failure. Included expert report and affidavit.	2017-18
Chevron Pipe Line Company	United States District Court of Utah, Central Division	2:12-cv-00287	Industry expert on behalf of plaintiff in the matter of electrical damage to an oil pipeline. Included expert report and deposition.	2016-17
Lorain-Medina Rural Electric Cooperative	State of Ohio Median County Common Pleas Court	15CIV0749	Industry expert on behalf of defendant in the matter of the application of an electric rate schedule dispute. Included expert report and deposition	2014-16

Utility / Entity	Jurisdiction Body	Case No.	Description	Year
Toronto Hydro-Electric System Limited	Ontario Energy Board	EB-2014-0116	Industry expert on behalf of Toronto Hydro. Developed filed report regarding independent review of the cost to serve developed environments including core downtown areas. Followed by oral testimony.	2014-15
Crow Wing Power	State of Minnesota District Court - Cass County	Court File No: 11-CV-12-1670	Testimony on behalf of defendant in the matter of a stray voltage lawsuit. Specific evidence related to conditions of underground distribution cable running adjacent to a dairy farm.	2013-14
MidAmerican Energy Company	State of Iowa District Court - Polk County	Law No. CL 114962	Industry expert on behalf of defendant providing engineering analysis showing the probable cause of failure of a 161kV transmission structure while under construction. Included affidavit of the analysis results and deposition.	2013
Toronto Hydro-Electric System Limited (THESL)	Ontario Energy Board	EB-2012-0064	Written and oral testimony regarding the replacement of aging electric infrastructure in the matter of THESL's application for 2012, 2013, and 2014 IRM Rate Adjustments and ICM Rate Adders	2012
Governor Dannel P. Malloy's Two Storm Panel	State of Connecticut	N/A	Expert witness presentation to Governor Malloy's Two Storm Panel regarding distribution system reliability in the aftermath of Tropical Storm Irene and 2011 Halloween nor'easter snowstorm.	2011
Mid-Kansas Electric Company	Kansas Corporation Commission	09-MKEE-969-RTS	Written expert rebuttal testimony on certain aspects of transmission and sub-transmission losses applied in proposed open access transmission tariffs and local access charges.	2009

Exhibit ESS-2

Power System Engineering, Inc.

Full-service consultants

MKEC 34.5 kV System Loss Analysis
Prairie Land Electric Cooperative

Prepared for:

Sunflower Electric Power Corporation

Prepared by:

Power System Engineering, Inc.

June, 2020

Prairie Land Electric Cooperative
34.5 kV System Loss Analysis
for
Sunflower Electric Power Corporation

Principal Contributors:

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Erik S. Sonju, P.E.

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Madison, WI 53713

www.powersystem.org

I hereby certify that this plan and report was prepared by me or under my direct supervision and that I am a duly Registered Professional Engineer under the laws of the State of Kansas.

Erik S. Sonju
June 19, 2020 Reg No.19492

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Tables and Figures

Appendix

1 Executive Summary

An engineering study was recently completed of the Mid-Kansas Electric Company, Inc (MKEC) 34.5kV sub-transmission system owned and operated by Sunflower Electric Power Corporation (Sunflower) distribution cooperative members. The subject matter of the engineering study was to estimate energy and demand losses that occurred during 2018. This report specifically details the losses associated with the 34.5kV system owned and operated by Prairie Land Electric Cooperative (Prairie Land).

The results of the study identified losses broken into three categories. These categories include 1) annual peak demand losses, 2) average monthly demand losses, and 3) energy losses. Figure 1-1 illustrates the summary of loss factors the Cooperative.

[redacted]

[redacted]

2 Background

Power System Engineering, Inc. (PSE) was contracted by Sunflower to perform a system loss analysis of the MKEC 34.5kV sub-transmission system. Prior to the commencement of this study, the system had been separated into six individual systems, which are currently owned and operated by Sunflower's six distribution members. These members include:

- Lane Scott Electric Cooperative, Inc.
- Southern Pioneer Electric Company (a wholly owned subsidiary of Pioneer Electric Cooperative, Inc.)
- Prairie Land Electric Cooperative, Inc.
- The Victory Electric Cooperative Association
- Western Cooperative Electric Association
- Wheatland Electric Cooperative Association

This report provides a summary of the loss factors associated with the 34.5 kV system owned and operated by Prairie Land Electric Cooperative.

[redacted]

[redacted]

[redacted]

Unlike other portions of the Sunflower transmission and member distribution systems, the Prairie Land 34.5kV system is not metered at all distribution substations. In general, distribution substations corresponding to wholesale loads are metered, while substations corresponding to retail loads are not metered. The absence of metering points at all 34.5kV input and output locations creates a complex arrangement from a system loss calculation standpoint. In other words, system losses cannot be simply calculated based on “metered energy in” less “metered energy out”. Rather, an engineering model needed to be established that could sufficiently represent all electrical component, loads, and associated losses.

The end results of the study efforts established the following loss factors of the Prairie Land 34.5kV system.

- Annual Coincident Peak Demand
- Monthly Average Coincident Peak Demand
- Energy

The loss factors were based on previous filings by MKEC with the Kansas Corporation Commission.

3 Methodology and Assumptions

3.1 General

Sunflower currently relies on Synergi Electric for their engineering model of the 34.5 kV system, which was provided to PSE for use in this analysis. The model is reflective of their normal system configuration at the time of the study, populated with coincident peak demand data per member service territory from 2018. Model development and load allocation was performed by Sunflower prior to its delivery to PSE.

Calculated system losses were based on the annual peak coincident demand of the Prairie Land 34.5 kV system and corresponding power factor. Component losses identified include line losses, transformer load losses, and transformer no-load losses. The annual coincident peak was chosen as opposed to monthly coincident peak[1] in an attempt to allow for easier correlation of load between exchange points when present. There are some instances in which an exchange point and its associated delivery point do not peak in the same month. Using annual coincident peak allows for the association of demand at the same time, which is more appropriate.

3.2 Line Losses

Line loss is the product of the square of the load current and line resistance (I^2R). Due to the squared component of this equation, line losses increase exponentially with the increase of load. Poor power factor will also increase line losses as additional current is needed to serve the same kW load. Line characteristics and resistance used for this study were not changed from the provided Synergi Electric model.

3.3 Transformer Losses

Loss characteristics of transformers are more complex than those of overhead lines. As mentioned above, losses on a line are due to the line's electrical resistance and are determined by the I^2R formula. Although transformers do exhibit this type of loss, they also display other types of losses. These losses can be broken down into load and no-load losses also known as winding and core losses, respectively.

3.3.1 Load Losses

Transformer I^2R losses are called load losses because they vary with the square of the load current. These losses are also referred to as winding losses because they occur mostly in the transformer's winding. Most of the losses occurring in heavily loaded transformers are load losses.

[1] Annual coincident peak is defined as Prairie Land's system peak coincident with the Sunflower peak. Monthly coincident peak is the delivery point peak coincident with the Sunflower peak.

3.3.2 No-Load Losses

Another type of transformer loss is no-load loss, or core loss. This type of loss is due to the electrical currents and magnetic fields necessary to magnetize the transformer core. No-load loss is present whenever a transformer is energized and remains constant regardless of the transformer load. Most of the losses occurring in lightly loaded transformers are no-load losses.

3.3.3 Transformer Characteristics

Transformer impedances were provided by Sunflower in the Synergi model. When available, transformer no-load losses and X/R ratios were determined from the transformer nameplate. These parameters were estimated for those transformers for which this data was not available. Transformer no-load losses were based on "Power Loss Management For the Restructured Utility Environment", written by the Cooperative Research Network. Transformer X/R ratios were based on General Electric's technical publication GET-3550F 0489 BLC. Table 3-1 illustrates the transformer characteristics that were used for this study. Note that percent impedance is not included, as this was defined by Sunflower, and is often particular to a specific transformer.

Table 3-1: Transformer Characteristcs

Typical Substation Transformer Losses					
Base Rating (MVA)	No-Load Losses (kW)	X/R	Base Rating (MVA)	No-Load Losses (kW)	X/R
0.05	0.14	1.50	6	10.80	12.80
0.15	0.41	2.20	7	11.20	13.80
0.25	0.65	2.80	7.5	12.00	14.20
0.275	0.74	2.80	8.4	11.76	14.80
0.3	0.75	3.00	10.5	13.65	16.00
0.45	0.99	3.20	12.5	16.25	16.80
0.5	1.05	4.00	13.3	15.96	18.00
0.56	1.18	4.25	14	14.98	18.50
0.6	1.32	4.50	22.4	22.40	22.00
0.75	1.40	5.00	25	24.00	23.90
1	1.67	6.00	27.5	26.40	24.20
1.1	1.76	6.20	28	25.20	24.50
1.5	2.10	7.00	30	27.00	25.00
2	3.30	7.70	33.6	30.24	25.50
2.5	3.88	8.20	34	30.60	26.50
2.8	4.06	8.20	35	31.50	27.50
3	4.35	10.10	42	37.80	29.00
3.75	5.06	11.30	46.7	42.03	30.00
4.2	5.46	11.50	56	49.28	31.00
5	10.00	12.20			

3.4 Demand Loss Factor

The established model provided a simulation of system conditions under static load. The static load condition chosen was the annual coincident peak load for each 138kV/115kV to 34.5kV delivery point. For the entirety of the system, this represented June and July peaks.

3.4.1 Annual Coincident Peak Demand Factor

Under the static load condition noted above, kW losses were calculated on both lines and transformers. The peak demand losses were calculated per substation area. The losses were separated into distribution line, transformer load, and transformer no-load losses. The losses are then divided by the metered coincident peak demand to determine the percentage of losses per substation and per member service area.

3.4.2 Monthly Average Coincident Peak Demand Factor

Since kW losses will vary with load, it is important to recognize that demand losses will change based on each month's coincident peak. For this reason, a Demand Adjustment Factor (DAJF) was established for each 138kV/115kV to 34.5kV delivery point. The equation for this factor is shown below.

$$DAJF = \frac{\sum Monthly\ Peak\ kW^2}{Peak\ Month\ kW^2 \times 12}$$

The DAJF is based on a ratio of the sum of the monthly peak demand squared over the annual peak demand squared times 12. The application of this factor provides a peak to average kW loss ratio that considers the exponential function of line and transformer load losses.

For the purpose of developing a monthly average coincident peak demand factor for this study, the DAJF was applied to the annual member system coincident peak demands for both line and transformer load component losses. Transformer no-load losses are the same during the monthly average coincident peak demand and annual coincident peak demand. Though some substations did peak in different months than the member coincident peak, the demand during the member coincident peak was used.

As stated, this factor is a monthly average and will be low during the peak summer months and high during the shoulder months. However, over the course of a 12-month period, the factor will provide the average total coincident demand losses.

3.5 Energy Loss Factor

When a loss study is performed, peak load conditions are often assumed in the first analysis. After peak load losses are determined, the total energy dissipated in losses over a year must then be determined. Since line and transformer load losses vary with the square of the load, average losses cannot be calculated using the average load. To accurately calculate average losses, the load on the equipment for each hour of the year must be determined. However, this method is impractical

for most applications and can only be done efficiently with highly detailed dynamic models. The more common method for determined average losses is the application of a loss factor. The equation for this factor is shown below.

$$Loss\ Factor = (0.16\ \times Load\ Factor) + \ (0.84\ \times Load\ Factor^2)$$

The above equation is based on RUS bulletins and was empirically derived from multiple tests made on typical electric cooperative loads.

For the purpose of developing an energy loss factor for this study, the loss factor was applied to the annual coincident peak demand losses for both line and transformer load component losses. Transformer no-load losses are the same throughout the year and do not correspond to the mentioned loss factor. Note that per the discussion of section 3.1, the loss factor was determined per substation at the month at which its entire associated system was at its peak demand.

4 Conclusions

4.1 Loss Factors

The 34.5kV system loss conclusions are provided in the appendix this report. The first page is a summary of the Prairie Land system 34.5kV losses, while the subsequent pages are the supporting data used to derive the loss factors.

In addition to the three loss factors defined earlier in this report, the losses by component and their percent of contribution to the overall loss factor for the respective system is also provided.

4.2 Potential Loss Saving Areas

The identification of potential loss saving areas should be compared against the cost of losses and the cost of construction to determine if they are economically justified. The scope of this study did not extend into this level of analysis; however, a few areas have been identified as potential candidates for loss savings.

[redacted]

[redacted]

- [redacted]

[redacted]

- [redacted]

[redacted]

4.2.2 Potential Transformer Loss Savings Areas

Once transformers are in place, it is difficult to economically justify the cost of replacement to a unit with lower losses. The best practice is to have a transformer loss evaluation process in place for transformer procurement and selection before a transformer is installed.

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Both demand and energy transformer losses can be reduced mainly via lower loss units. However, as mentioned earlier, it is typically not economical to replace existing units, but rather evaluate future transformers during procurement and selection. Loading practices and cost of losses will typically dictate the most economical transformers in terms of both load and no-load losses.

Appendix

[redacted]

[redacted]

[redacted]

Exhibit ESS-2

[redacted]

Exhibit ESS-2

[redacted]

Exhibit ESS-2

[redacted]

Power System Engineering, Inc.

Full-service consultants

MKEC 34.5 kV System Loss Analysis
The Victory Electric Cooperative Association

Prepared for:

Sunflower Electric Power Corporation

Prepared by:

Power System Engineering, Inc.

June, 2020

The Victory Electric Cooperative Association
34.5 kV System Loss Analysis
for
Sunflower Electric Power Corporation

Principal Contributors:

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Erik S. Sonju, P.E.

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1532 W. Broadway
Madison, WI 53713

www.powersystem.org

I hereby certify that this plan and report was prepared by me or under my direct supervision and that I am a duly Registered Professional Engineer under the laws of the State of Kansas.

Erik S. Sonju

Erik S. Sonju
June 19, 2020 Reg No.19492

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Tables and Figures

Appendix

1 Executive Summary

An engineering study was recently completed of the Mid-Kansas Electric Company, Inc (MKEC) 34.5kV sub-transmission system owned and operated by Sunflower Electric Power Corporation (Sunflower) distribution cooperative members. The subject matter of the engineering study was to estimate energy and demand losses that occurred during 2018. This report specifically details the losses associated with the 34.5kV system owned and operated by The Victory Electric Cooperative Association (Victory).

The results of the study identified losses broken into three categories. These categories include 1) annual peak demand losses, 2) average monthly demand losses, and 3) energy losses. Figure 1-1 illustrates the summary of loss factors the Cooperative.

[redacted]

[redacted]

2 Background

Power System Engineering, Inc. (PSE) was contracted by Sunflower to perform a system loss analysis of the MKEC 34.5kV sub-transmission system. Prior to the commencement of this study, the system had been separated into six individual systems, which are currently owned and operated by Sunflower's six distribution members. These members include:

- Lane Scott Electric Cooperative, Inc.
- Southern Pioneer Electric Company (a wholly owned subsidiary of Pioneer Electric Cooperative, Inc.)
- Prairie Land Electric Cooperative, Inc.
- The Victory Electric Cooperative Association
- Western Cooperative Electric Association
- Wheatland Electric Cooperative Association

This report provides a summary of the loss factors associated with the 34.5 kV system owned and operated by The Victory Electric Cooperative Association.

[redacted]

[redacted]

[redacted]

[redacted]

Unlike other portions of the Sunflower transmission and member distribution systems, the Victory 34.5kV system is not metered at all distribution substations. In general, distribution substations corresponding to wholesale loads are metered, while substations corresponding to retail loads are not metered. The absence of metering points at all 34.5kV input and output locations creates a complex arrangement from a system loss calculation standpoint. In other words, system losses cannot be simply calculated based on "metered energy in" less "metered energy out". Rather, an engineering model needed to be established that could sufficiently represent all electrical component, loads, and associated losses.

The end results of the study efforts established the following loss factors of the Victory 34.5kV system.

- Annual Coincident Peak Demand
- Monthly Average Coincident Peak Demand
- Energy

The loss factors were based on previous filings by MKEC with the Kansas Corporation Commission.

3 Methodology and Assumptions

3.1 General

Sunflower currently relies on Synergi Electric for their engineering model of the 34.5 kV system, which was provided to PSE for use in this analysis. The model is reflective of their normal system configuration at the time of the study, populated with coincident peak demand data per member service territory from 2018. Model development and load allocation was performed by Sunflower prior to its delivery to PSE.

Calculated system losses were based on the annual peak coincident demand of the Victory 34.5 kV system and corresponding power factor. Component losses identified include line losses, transformer load losses, and transformer no-load losses. The annual coincident peak was chosen as opposed to monthly coincident peak[1] in an attempt to allow for easier correlation of load between exchange points when present. There are some instances in which an exchange point and its associated delivery point do not peak in the same month. Using annual coincident peak allows for the association of demand at the same time, which is more appropriate.

3.2 Line Losses

Line loss is the product of the square of the load current and line resistance (I^2R). Due to the squared component of this equation, line losses increase exponentially with the increase of load. Poor power factor will also increase line losses as additional current is needed to serve the same kW load. Line characteristics and resistance used for this study were not changed from the provided Synergi Electric model.

3.3 Transformer Losses

Loss characteristics of transformers are more complex than those of overhead lines. As mentioned above, losses on a line are due to the line's electrical resistance and are determined by the I^2R formula. Although transformers do exhibit this type of loss, they also display other types of losses. These losses can be broken down into load and no-load losses also known as winding and core losses, respectively.

3.3.1 Load Losses

Transformer I^2R losses are called load losses because they vary with the square of the load current. These losses are also referred to as winding losses because they occur mostly in the transformer's winding. Most of the losses occurring in heavily loaded transformers are load losses.

[1] Annual coincident peak is defined as Victory's system peak coincident with the Sunflower peak. Monthly coincident peak is the delivery point peak coincident with the Sunflower peak.

3.3.2 No-Load Losses

Another type of transformer loss is no-load loss, or core loss. This type of loss is due to the electrical currents and magnetic fields necessary to magnetize the transformer core. No-load loss is present whenever a transformer is energized and remains constant regardless of the transformer load. Most of the losses occurring in lightly loaded transformers are no-load losses.

3.3.3 Transformer Characteristics

Transformer impedances were provided by Sunflower in the Synergi model. When available, transformer no-load losses and X/R ratios were determined from the transformer nameplate. These parameters were estimated for those transformers for which this data was not available. Transformer no-load losses were based on "Power Loss Management For the Restructured Utility Environment", written by the Cooperative Research Network. Transformer X/R ratios were based on General Electric's technical publication GET-3550F 0489 BLC. Table 3-1 illustrates the transformer characteristics that were used for this study. Note that percent impedance is not included, as this was defined by Sunflower, and is often particular to a specific transformer.

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0.05	0.14	1.50	6	10.80	12.80
0.15	0.41	2.20	7	11.20	13.80
0.25	0.65	2.80	7.5	12.00	14.20
0.275	0.74	2.80	8.4	11.76	14.80
0.3	0.75	3.00	10.5	13.65	16.00
0.45	0.99	3.20	12.5	16.25	16.80
0.5	1.05	4.00	13.3	15.96	18.00
0.56	1.18	4.25	14	14.98	18.50
0.6	1.32	4.50	22.4	22.40	22.00
0.75	1.40	5.00	25	24.00	23.90
1	1.67	6.00	27.5	26.40	24.20
1.1	1.76	6.20	28	25.20	24.50
1.5	2.10	7.00	30	27.00	25.00
2	3.30	7.70	33.6	30.24	25.50
2.5	3.88	8.20	34	30.60	26.50
2.8	4.06	8.20	35	31.50	27.50
3	4.35	10.10	42	37.80	29.00
3.75	5.06	11.30	46.7	42.03	30.00
4.2	5.46	11.50	56	49.28	31.00
5	10.00	12.20			

3.4 Demand Loss Factor

The established model provided a simulation of system conditions under static load. The static load condition chosen was the annual coincident peak load for each 138kV/115kV to 34.5kV delivery point. For the entirety of the system, this represented June and July peaks.

3.4.1 Annual Coincident Peak Demand Factor

Under the static load condition noted above, kW losses were calculated on both lines and transformers. The peak demand losses were calculated per substation area. The losses were separated into distribution line, transformer load, and transformer no-load losses. The losses are then divided by the metered coincident peak demand to determine the percentage of losses per substation and per member service area.

3.4.2 Monthly Average Coincident Peak Demand Factor

Since kW losses will vary with load, it is important to recognize that demand losses will change based on each month's coincident peak. For this reason, a Demand Adjustment Factor (DAJF) was established for each 138kV/115kV to 34.5kV delivery point. The equation for this factor is shown below.

$$DAJF = \frac{\sum Monthly\ Peak\ kW^2}{Peak\ Month\ kW^2 \times 12}$$

The DAJF is based on a ratio of the sum of the monthly peak demand squared over the annual peak demand squared times 12. The application of this factor provides a peak to average kW loss ratio that considers the exponential function of line and transformer load losses.

For the purpose of developing a monthly average coincident peak demand factor for this study, the DAJF was applied to the annual member system coincident peak demands for both line and transformer load component losses. Transformer no-load losses are the same during the monthly average coincident peak demand and annual coincident peak demand. Though some substations did peak in different months than the member coincident peak, the demand during the member coincident peak was used.

As stated, this factor is a monthly average and will be low during the peak summer months and high during the shoulder months. However, over the course of a 12-month period, the factor will provide the average total coincident demand losses.

3.5 Energy Loss Factor

When a loss study is performed, peak load conditions are often assumed in the first analysis. After peak load losses are determined, the total energy dissipated in losses over a year must then be determined. Since line and transformer load losses vary with the square of the load, average losses cannot be calculated using the average load. To accurately calculate average losses, the load on the equipment for each hour of the year must be determined. However, this method is impractical

for most applications and can only be done efficiently with highly detailed dynamic models. The more common method for determined average losses is the application of a loss factor. The equation for this factor is shown below.

$$Loss\ Factor = (0.16\ \times Load\ Factor) + \ (0.84\ \times Load\ Factor^2)$$

The above equation is based on RUS bulletins and was empirically derived from multiple tests made on typical electric cooperative loads.

For the purpose of developing an energy loss factor for this study, the loss factor was applied to the annual coincident peak demand losses for both line and transformer load component losses. Transformer no-load losses are the same throughout the year and do not correspond to the mentioned loss factor. Note that per the discussion of section 3.1, the loss factor was determined per substation at the month at which its entire associated system was at its peak demand.

4 Conclusions

4.1 Loss Factors

The 34.5kV system loss conclusions are provided in the appendix this report. The first page is a summary of the Victory system 34.5kV losses, while the subsequent pages are the supporting data used to derive the loss factors.

In addition to the three loss factors defined earlier in this report, the losses by component and their percent of contribution to the overall loss factor for the respective system is also provided.

4.2 Potential Loss Saving Areas

The identification of potential loss saving areas should be compared against the cost of losses and the cost of construction to determine if they are economically justified. The scope of this study did not extend into this level of analysis; however, a few areas have been identified as potential candidates for loss savings.

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4.2.2 Potential Transformer Loss Savings Areas

Once transformers are in place, it is difficult to economically justify the cost of replacement to a unit with lower losses. The best practice is to have a transformer loss evaluation process in place for transformer procurement and selection before a transformer is installed.

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Both demand and energy transformer losses can be reduced mainly via lower loss units. However, as mentioned earlier, it is typically not economical to replace existing units, but rather evaluate future transformers during procurement and selection. Loading practices and cost of losses will typically dictate the most economical transformers in terms of both load and no-load losses.

Appendix

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Exhibit ESS-3

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Exhibit ESS-3

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Power System Engineering, Inc.

Full-service consultants

MKEC 34.5 kV System Loss Analysis Western Cooperative Electric Association

Prepared for:

Sunflower Electric Power Corporation

Prepared by:

Power System Engineering, Inc.

June, 2020

Western Cooperative Electric Association
34.5 kV System Loss Analysis
for
Sunflower Electric Power Corporation

Principal Contributors:

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I hereby certify that this plan and report was prepared by me or under my direct supervision and that I am a duly Registered Professional Engineer under the laws of the State of Kansas.

Erik S. Sonju

Erik S. Sonju
June 19, 2020 Reg No.19492

Table of Contents

Tables and Figures

Appendix

1 Executive Summary

An engineering study was recently completed of the Mid-Kansas Electric Company, Inc (MKEC) 34.5kV sub-transmission system owned and operated by Sunflower Electric Power Corporation (Sunflower) distribution cooperative members. The subject matter of the engineering study was to estimate energy and demand losses that occurred during 2018. This report specifically details the losses associated with the 34.5kV system owned and operated by Western Cooperative Electric Association (Western).

The results of the study identified losses broken into three categories. These categories include 1) annual peak demand losses, 2) average monthly demand losses, and 3) energy losses. Figure 1-1 illustrates the summary of loss factors the Cooperative.

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2 Background

Power System Engineering, Inc. (PSE) was contracted by Sunflower to perform a system loss analysis of the MKEC 34.5kV sub-transmission system. Prior to the commencement of this study, the system had been separated into six individual systems, which are currently owned and operated by Sunflower's six distribution members. These members include:

- Lane Scott Electric Cooperative, Inc.
- Southern Pioneer Electric Company (a wholly owned subsidiary of Pioneer Electric Cooperative, Inc.)
- Prairie Land Electric Cooperative, Inc.
- The Victory Electric Cooperative Association
- Western Cooperative Electric Association
- Wheatland Electric Cooperative Association

This report provides a summary of the loss factors associated with the 34.5 kV system owned and operated by Western Cooperative Electric Association.

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Unlike other portions of the Sunflower transmission and member distribution systems, the Western 34.5kV system is not metered at all distribution substations. In general, distribution substations corresponding to wholesale loads are metered, while substations corresponding to retail loads are not metered. The absence of metering points at all 34.5kV input and output locations creates a complex arrangement from a system loss calculation standpoint. In other words, system losses cannot be simply calculated based on “metered energy in” less “metered energy out”. Rather, an engineering model needed to be established that could sufficiently represent all electrical component, loads, and associated losses.

The end results of the study efforts established the following loss factors of the Western 34.5kV system.

- Annual Coincident Peak Demand
- Monthly Average Coincident Peak Demand
- Energy

The loss factors were based on previous filings by MKEC with the Kansas Corporation Commission.

3 Methodology and Assumptions

3.1 General

Sunflower currently relies on Synergi Electric for their engineering model of the 34.5 kV system, which was provided to PSE for use in this analysis. The model is reflective of their normal system configuration at the time of the study, populated with coincident peak demand data per member service territory from 2018. Model development and load allocation was performed by Sunflower prior to its delivery to PSE.

Calculated system losses were based on the annual peak coincident demand of the Western 34.5 kV system and corresponding power factor. Component losses identified include line losses, transformer load losses, and transformer no-load losses. The annual coincident peak was chosen as opposed to monthly coincident peak[1] in an attempt to allow for easier correlation of load between exchange points when present. There are some instances in which an exchange point and its associated delivery point do not peak in the same month. Using annual coincident peak allows for the association of demand at the same time, which is more appropriate.

3.2 Line Losses

Line loss is the product of the square of the load current and line resistance (I^2R). Due to the squared component of this equation, line losses increase exponentially with the increase of load. Poor power factor will also increase line losses as additional current is needed to serve the same kW load. Line characteristics and resistance used for this study were not changed from the provided Synergi Electric model.

3.3 Transformer Losses

Loss characteristics of transformers are more complex than those of overhead lines. As mentioned above, losses on a line are due to the line's electrical resistance and are determined by the I^2R formula. Although transformers do exhibit this type of loss, they also display other types of losses. These losses can be broken down into load and no-load losses also known as winding and core losses, respectively.

3.3.1 Load Losses

Transformer I^2R losses are called load losses because they vary with the square of the load current. These losses are also referred to as winding losses because they occur mostly in the transformer's winding. Most of the losses occurring in heavily loaded transformers are load losses.

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[1] Annual coincident peak is defined as Western's system peak coincident with the Sunflower peak. Monthly coincident peak is the delivery point peak coincident with the Sunflower peak.

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Transformer impedances were provided by Sunflower in the Synergi model. When available, transformer no-load losses and X/R ratios were determined from the transformer nameplate. These parameters were estimated for those transformers for which this data was not available. Transformer no-load losses were based on "Power Loss Management For the Restructured Utility Environment", written by the Cooperative Research Network. Transformer X/R ratios were based on General Electric's technical publication GET-3550F 0489 BLC. Table 3-1 illustrates the transformer characteristics that were used for this study. Note that percent impedance is not included, as this was defined by Sunflower, and is often particular to a specific transformer.

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The established model provided a simulation of system conditions under static load. The static load condition chosen was the annual coincident peak load for each 138kV/115kV to 34.5kV delivery point. For the entirety of the system, this represented June and July peaks.

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Appendix

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Exhibit ESS-4

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Exhibit ESS-4

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