Expert Witness Testimony of Thomas J. Sullivan, Jr.

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Mains Classification and Weighting Factor Study

Introduction

Supporting studies are prepared for the class cost of service study that develop the classification of mains and the customer weighting factors for service lines, meters and regulators, and customer accounting-related costs. In these studies, the following relationships are analyzed:

1. Mains - Account 367 and Account 376 - Development of the classification of mains investment between capacity, commodity, and customer related cost;
2. Service Lines - Account 380 - Development of weighting factors that recognize the relative cost of service lines for each customer class;
3. Meters and Regulators - Accounts 381 through 385 - Development of weighting factors that recognize the relative cost of the combined meter and regulator installation for each customer class; and
4. Customer Accounting - Development of weighting factors that recognize the relative cost of providing customer accounting, meter reading, billing, and customer service for each customer class.

The data relied upon for the mains, service lines, and meters and regulators analyses are contained in the Company's detailed property records. The base data underlying these analyses are the original cost and quantity data in the Company's continuing property records as of December 31, 2019, with adjustments related to large projects that are not captured in that data which will be discussed in more detail below. The relative relationships in these analyses are developed based on original costs restated to current cost levels (2019). We restate the original cost levels using Handy-Whitman cost indices for the North Central Region. By developing relationships based on current cost levels, inflationary impacts do not affect the analyses and more stable relationships result over time since the timing of renewals and replacements do not distort the analyses.

The Handy-Whitman cost indices are published twice a year by Whitman, Requardt and Associates, LLP and contain cost indices and construction cost trends back to 1912 for electric, gas, and water utility assets. The indices for gas utilities are developed by the FERC Uniform System of Accounts for six regions in the United States. These indices have been published since the 1920s and are a utility standard for determining inflation adjusted cost and replacement cost analyses for utility assets.

The purpose of the mains classification analysis is to determine the relative relationships between the commodity, capacity, and customer functions served by these facilities. The underlying assets are very long-lived; as such, the underlying costs of the assets change significantly over the useful life of these assets. Further, the construction of the distribution system follows a natural progression with higher diameter, higher capacity facilities built first, and the smaller diameter facilities built to serve individual or small groups of customers are constructed as service is required. In addition, changes in construction and maintenance practices over time have resulted in replacement programs that are not necessarily uniform. In order to focus the analysis on the relative amount of investment required to serve commodity, capacity, and customer functions that are not impacted by timing or the transient effects of when assets are replaced or renewed, it is important to remove such effects from the analyses.

Restating the original costs that are based on the vintage date of the installation to current cost by trending the original costs to current costs mitigates the effects of time and transient effects; thus producing a more stable result over time that better reflects the function the assets serve.

Likewise, it is important to remove timing effects from the determination of the relative costs of service lines, and meters and regulators by restating these costs to current cost levels such that we are truly reflecting the differences in the size and capacity of the facilities used to serve different customer classes. For meters and regulators, it is also important to recognize that meters and regulators are not permanently fixed and are fungible. It is not uncommon for a meter to be removed from one installation and then be installed at another location of comparable requirements.

Mains Classification Study

There are three basic components of cost associated with service from a gas distribution system. These cost components are capacity- (peak), energy- (commodity or throughput), and customer-related. Investment in mains is related to all three of these cost components. We generally consider transmission mains to serve capacity and energy functions, and distribution mains to serve customer and capacity functions.

As a functional classification, transmission (from an engineering, cost allocation perspective) represents the movement of natural gas from sources of supply to general areas of consumption. The distribution function, on the other hand, represents the movement of gas within general areas of consumption to individual customers.

The definition of the transmission and distribution function is not the same things as the FERC Uniform System of Accounts Definition of transmission and distribution. As indicated above, the transmission function for cost allocation purposes includes facilities that move gas from sources of supply to general areas of consumption. This function is generally served by higher diameter, higher pressure mains that only directly serve very large customers. Facilities that are booked to both the transmission mains account (primarily Account 367) and distribution mains (primarily Account 376) serve this function. Therefore, higher diameter, higher pressure distribution mains also serve a transmission function.

Due to the fact that Black Hills has made significant mains, primarily Account 376, investment over the last year and is proposing a significant pro forma adjustment, we included a review of both plant completed but not yet classified as of December 31, 2019 as well as a review of the projects included in the pro forma adjustment. Based on that review, the vast majority of the investment has been to replace aging pipe with comparable sized facilities. As discussed earlier in this memorandum, one of the reasons we used trended original cost in our analyses is to minimize the impact of large replacement programs. If the replacements are with comparable sized facilities, the impact our analysis is thus minimal. However, we did identify one very large project that consisted of very large diameter pipe that included not only replacement with larger pipe but also incremental pipe. This project was located in Lincoln and includes approximately $31 million in new investment of 12- and 16- inch diameter steel mains. This project is in the category of completed but not yet classified and was thus not in the December 31, 2019 continuing property record data used in our study. Thus, our study includes not only adding the new investment but removing the facilities to be replaced. This adjustment slightly increases the amount of pipe classified as serving a transmission function.

Prior to discussing the specific classification used in the current class cost of service study, discussions of the mains classification studies from the most recent SourceGas (2011) and Black Hills (2009) rate cases are warranted. In the present case, the two systems are being consolidated and the mains classification study for this case is based on the consolidated system. Historically, there were differences between the two legacy systems that was reflected in the prior mains classification studies. In addition, in both of the last rate cases for the legacy systems, certain mainline non-jurisdictional industrial customers were directly assigned all of the plant required to serve them, thus eliminating any allocation of distribution mains related facilities that are not required or used and useful to providing them service. These directly assigned mains are excluded from the mains classification study used to determine the classification and allocation of mains to the non-direct assigned jurisdictional and non-jurisdictional customers.

2009 Black Hills Mains Classification Study

The mains classification study used in the last legacy Black Hills/Aquila rate case was prepared in 2006 and used for the 2009 Nebraska rate case. The legacy Black Hills/Aquila had approximately $4 million (5 percent of the total mains investment) in plant booked to Account 367- Transmission Mains. This investment was assigned 50/50 to Transmission – Capacity/Transmission-Commodity. Facilities in Account 376- Distribution Mains with a diameter of 8 inches or greater were assigned to the Transmission Function (12 percent of Account 376 investment) using the same 50/50 assignment used for Account 367 mains and the remainder (88 percent) assigned to the Distribution Function using the methodology discussed later in this memorandum. Further, using the same methodology discussed later in this memorandum to determine the Capacity/Customer split for distribution function facilities, the resulting classification of Account 376 mains (composite of both the transmission and distribution functions) was 32.93 percent Capacity, 61.08 percent Customer, and 5.99 percent Commodity.

In the 2009 Black Hills rate case, there was one large volume non-jurisdictional customer (Cargill) directly served off the interstate pipeline system. The net plant investment (plant investment minus the customer's contribution) associated with all the pipeline facilities required to serve this customer were directly assigned to this customer. This customer was thus not allocated any of the Company's other transmission and distribution pipeline facilities, and the other customers were not allocated any of the pipeline investment required to serve this customer This direct assignment principal has been consistently approved by the Nebraska Public Service Commission for both the legacy Black Hills/Aquila and legacy SourceGas systems.

2011 SourceGas Mains Classification Study

The mains classification study used in the last legacy SourceGas rate case was prepared in 2011 and used for the 2011 Nebraska rate case. The legacy SourceGas did not have any investment directly booked to Account 367. However, the legacy SourceGas system included a significant amount of transmission laterals that were spun down to the distribution system at the time that Kinder Morgan separated its transmission and distribution businesses as a result of FERC Order 636. These transmission laterals primarily interconnect the widely dispersed rural towns served by the legacy SourceGas system. Based on the DOT reports available at the time of the 2011 Study, there was 1,210 miles of these transmission laterals that were reclassified as distribution on the SourceGas books. Based on the 2011 study, it was determined that 31.1 percent of the mains booked to Account 376 was historically related to plant that was booked to Account 367, with the remaining 68.9 percent booked to distribution.

In the SourceGas class cost of service study, 31.1 percent of the amount booked to Account 376 was treated as though the costs were booked to Account 367. This 31.1 percent was then assigned to the Transmission Function with 50 percent assigned to Capacity and 50 percent to Commodity. The remaining 68.9 percent was treated as though the costs were booked to Account 376 and further analyzed to determine the appropriate transmission and distribution functional split for the Account 376 costs.

Facilities in the "restated" Account 376- Distribution Mains with a diameter of 4 inches or greater were assigned to the Transmission Function (27 percent of Account 376 investment) using the same 50/50 assignment used for Account 367 mains and the remainder (63 percent) assigned to the Distribution Function using the methodology discussed later in this memorandum. Further, using the same methodology discussed later in this memorandum to determine the Capacity/Customer split for distribution function facilities, the resulting classification of Account 376 mains (composite of both the transmission and distribution functions) was 40.69 percent Capacity, 45.74 percent Customer, and 13.56 percent Commodity.

In the 2011 SourceGas rate case, there were 11 super-high volume non-jurisdictional customers who were directly assigned the plant used to serve them (similar to Cargill on the Black Hills system). The net plant investment (plant investment minus the customer's contribution) associated with the pipeline facilities required to serve these customers were directly assigned to these customers. These customers were thus not allocated any of the Company's other transmission and distribution pipeline facilities, and the other customers were not allocated any of the pipeline investment required to serve these customers. In addition, there were 7 customers that were directly served off facilities that were classified as transmission Account 367 mains. These customers were allocated costs classified as Account 367 transmission mains but not distribution mains related costs. This direct assignment principal and recognition of customers served off of Company transmission facilities have been consistently approved by the Nebraska Public Service Commission for both the legacy Black Hills/Aquila and legacy SourceGas systems.

Summary Discussion and Comparison between the two legacy systems

As seen in the different results between the two systems, there are significant differences between the facilities of the legacy SourceGas and Black Hills/Aquila systems. The most obvious difference is that the legacy SourceGas system is much more rural and serves a much more geographically dispersed area. Most of the legacy Black Hills/Aquila system serves urban customers in Lincoln and the suburbs of Omaha, with a few towns from the former Minnegasco system that were served off the former Kinder Morgan (and KN Energy) transmission system similar to towns of the legacy SourceGas system. Further, the transmission facilities on the legacy SourceGas system were smaller diameter than those used on the legacy Black Hills/Aquila system recognizing that the geographically dispersed towns on the legacy SourceGas system had relatively low demand and thus capacity required, especially compared to Lincoln and Omaha. Finally, urban systems usually have a higher customer component of mains because of the greater customer density and thus mains are built to extend service to connect customers rather than provide capacity. Thus, comparing the two systems, the SourceGas mains classification has a much greater assignment to the Transmission functions and thus a higher assignment of Capacity and Commodity and lower assignment to Customer when compared to the legacy Black Hills/Aquila. One would expect that the results of the analysis of the consolidated systems to be somewhere in between the results of the two separate systems.

Direct Served Customers – Consolidated Black Hills Nebraska Gas System

On the consolidated Black Hills system there are three classes of direct served customers; two classes are the same as those on the prior legacy systems and one contains a new class of customers that has evolved since the last rate cases. The two historical classes are customers who are directly connected to interstate pipelines and customers who are served from the Company transmission system. The new class includes natural gas suppliers who directly supply natural gas into the Company's transmission or distribution system.

As in the past, investment associated with customers directly connected to interstate (third-party) transmission systems will be directly assigned to those customers. Thus, no other customers will be allocated any of those facilities that directly serve these customers and these directly served customers will not be allocated any of the other Company transmission or distribution facilities that are not used and useful to their service. In the workpapers and class cost of service study, these customers will be aggregated into a separate class (as has been done in the past legacy studies), and this class will be referred to as "Negotiated-Direct".

The second class which historically appeared in the legacy SourceGas cost of service studies are customer served from Company transmission facilities. These customers are allocated costs of facilities classified as transmission but are not allocated costs classified as distribution. This class will be referred to as "Negotiated-Transmission".

The third class, which is a new class, includes facilities associated with directly connected suppliers of natural gas. The nature of this service is fundamentally different from the service provided to sales or transportation customers. The service provided by the Company is providing facilities that connect the suppliers natural gas production facilities to the Company's transmission or distribution system for delivery to the Company's customers. Currently, the suppliers are landfills that produce renewable natural gas ("RNG"), but could include other facilities that also produce RNG. The investment made by the Company to connect these suppliers will be directly assigned to this customer class and no other costs associated with the Company's transmission and distribution system will be allocated to these suppliers since the facilities used and useful to these operations are used to supply natural into the Company's system, not take delivery of gas from the Company's or third-party systems. This class will be referred to as "Negotiated-Supply".

The determination of which customers are assigned to these three classes was based on detailed study of the Company and third-party transmission facilities used to serve these customers as shown in the Company's GIS system. Any plant directly assigned to these customers is based on the plant recorded in the Company's continuing property records including allowance for any direct construction contribution made by these customers. In some cases, these customers are served directly off third-party transmission systems with no facilities owned by the Company, and thus required no direct investment in facilities. The maps, investment, and other allocation related information for these customers will be included as confidential workpapers due to the fact that they contain customer specific information. In total, there are 9 Negotiated-Transmission customers, 15 Negotiated-Direct customers, and 2 Negotiated-Supply suppliers.

The remaining non-jurisdictional large volume customers not in these three classes are assigned to non-jurisdictional classes in the same manner as they have been treated in prior legacy class cost of service studies.

Transmission Facilities – Consolidated Black Hills Nebraska Gas System

As discussed earlier, there are three broad categories of facilities that provide the transmission function. First, there are the assets booked to Account 367 – Transmission Mains from the legacy Black Hills/Aquila system. Second, there are assets booked to Account 376 – Distribution Mains from the legacy SourceGas system that were transferred from the former Kinder Morgan transmission system that resulted from the separation of the supply, transmission, and distribution functions resulting from implementation of FERC Order No. 636. Third, there are the remaining high pressure, larger diameter Account 376 Mains on both legacy systems that provide a transmission function.

[system map – Schedule 2-1]

The allocation of investment in facilities serving a transmission function should recognize that these facilities are used to meet both peak and annual requirements of customers. These facilities, though sized to meet system peak requirements, are also influenced by annual requirements. To recognize this dual nature, the cost of these facilities should be allocated on a basis that recognizes both peak and annual use of the facilities. A variety of methods have been used to recognize the dual nature of these facilities. For the purpose of allocating transmission-related costs on the Black Hills Nebraska Gas ("BH Nebraska Gas" or "Company") system, I recommend that we give equal weighting to the capacity and commodity functions, consistent with how these facilities have been assigned in past legacy SourceGas and Black Hills/Aquila rate cases.

The assignment of transmission-related costs equally (50/50) to capacity and commodity has historically been referred to as the Atlantic Seaboard Method. Between the early 1950's and 1973, the primary method used by the Federal Power Commission (now FERC) was the Atlantic Seaboard methodology. Under this methodology, fixed costs were assigned equally (50/50) to the fixed (demand or capacity) and variable (commodity) cost classifications. More recently, the current methodology used by the FERC has evolved to a straight fixed variable ("SFV") methodology that assigns 100% of fixed costs to the capacity function.

In the Nebraska class cost of service study there are three separate and distinct groups of facilities that perform transmission functions:

1. Account 367 – Transmission Mains
2. Account 376 – Distribution Mains on the legacy SourceGas system that were reclassified to distribution plant as a result of FERC Order 636 but are essentially transmission facilities. The Company's DOT/PHMSA reports still segregate these facilities.
3. Account 376 – Distribution Mains on both legacy systems that perform a transmission function by moving gas from general areas of supply to general areas of consumption.

In the class cost of service study, costs directly booked to Account 367 will be functionalized as Transmission and classified 50 percent to Commodity and 50 percent to Capacity consistent with their treatment in prior Black Hills/Aquila rate cases. The facilities booked to Account 367 are summarized in Schedule 2-3, lines 1 through 7.

In the class cost of service study, costs booked to Account 376 that are associated with former Kinder Morgan transmission facilities will be functionalized as Transmission and classified 50 percent to Commodity and 50 percent to Capacity consistent with their treatment in prior SourceGas rate cases. Schedule 2-2 summarizes information from the Company's DOT/PHMSA reports for both the legacy systems. These reports are prepared separating the legacy SourceGas and Black Hills/Aquila systems and also treat the legacy Kinder Morgan transmission facilities on the legacy SourceGas system as transmission. As shown in Schedule 2-2, there are 1,219 miles of transmission facilities on the SourceGas system. This compares to 1,210 miles at the time of the last SourceGas rate case; thus, these facilities have changed little over the last 10 years. According to the DOT report all of this pipe is steel and the breakdown by size is also summarized in Schedule 2-2.

Using the quantity of pipe by size from the DOT reports and the unit trended original cost of SourceGas steel mains based on analysis of the Company's continuing property records, an estimate of the trended original cost of the former Kinder Morgan transmission facilities is developed on lines 8-15 of Schedule 2-3 using the same methodology used to functionalize and classify these costs in the last SourceGas rate case. The total trended original cost of these facilities equals 12.75 percent of the total trended original cost of the facilities booked to Account 376. Thus, 12.75 percent of the investment in Account 376 will be functionalized as Transmission with 50 percent classified as Commodity and 50 percent classified as Capacity.

The remaining 87.25 percent of the investment in Account 376 will be treated as Distribution facilities that are functionalized and classified as discussed in the next section of this report. These facilities are summarized on lines 43-57 of Schedule 2-3.

Distribution Facilities – Consolidated Black Hills Nebraska Gas System

In the Nebraska class cost of service study. The distribution facilities (the 87.25 percent of investment in Account 376) served both transmission and distribution functions. As previously discussed, the transmission represents the movement of gas from areas of supply to general areas of consumption. Higher pressure, larger diameter facilities on the distribution systems serve this transmission function.

Only very large customers are directly connected to these facilities and these facilities generally move gas from the transmission receipt point (town border stations) to district regulator stations that reduce the higher pressure down to the lower distribution pressures used to deliver gas to areas of consumption. The allocation of these distribution facilities that serve a transmission function are classified in the same manner as discussed above for transmission facilities (50 percent Capacity and 50 percent Commodity.

The allocation of investment in facilities serving a distribution function should recognize that the cost of these facilities is driven by two principle factors. First, is the cost of extending the system to connect individual customers. Second, is the cost associated with the capacity (peak day) requirements of the customers connected. Though facilities serving a distribution function are also used to meet customers' annual requirements, due to the local nature of the facilities and their customer specific cost, we do not allocate any cost associated with the distribution function on the basis of annual throughput. Reasonable and consistent results are achieved by allocating costs of facilities, which are functionally classified as distribution, on the basis of the number of customers and peak period requirements.

The customer-related function of mains is not the same as the customer-specific cost component. Within the distribution function, the service lines, meters and regulators, are for the most part, used to serve individual customers. Costs associated with these items are considered customer-specific. There is also a customer component of distribution mains which recognizes the cost implications of the distance between individual customers or customer density on the cost of distribution mains. The quantity (i.e. length) of smaller diameter distribution mains is primarily driven by the distance between customers and customer density.

As discussed earlier, the 50% capacity and 50% commodity assignments are based on application of the Atlantic Seaboard method which was a transmission facility cost assignment methodology used at the Federal Power Commission over 50 years ago. It would only be appropriate to ever apply this methodology on distribution mains that perform a function similar to transmission mains. For the lower capacity, smaller diameter mains, customer density and the relative distance between customers is a significant driver in the quantity of pipe that must be installed and also contributes to the need for increased pipe diameter both of which have a significant impact on cost. The quantity (length) of pipe required to serve smaller residential and commercial customers is greater in rural and less populated urban areas, thus, resulting in a higher unit cost per customer associated with the mains required to serve these customers. In urban areas, there are significantly more multi-family dwelling units and strip type retailing, and even single-family homes tend to be clustered closer together than is the case in rural or even suburban areas. Further, as distance increases for a given demand, pipe diameter must also be increased to reflect the cumulative effect of the friction losses (and resulting pressure decline) in the pipe. This also increases the relative unit cost of mains per customer in rural compared to urban areas. These customer related cost drivers are primarily a characteristic of the design of the distribution system that serves residential and small commercial customers. Larger customers are typically served at higher pressures off larger diameter pipe where capacity and commodity are the primary design considerations.

We assign mains larger than a certain size as serving a transmission function. I base this assignment on the relative capacity of the various sizes of pipe. Pipeline flow formulas generally suggest that the capacity of a pipeline is proportional to its diameter to something on the order of the 2.5 power. Raising the diameter to the 2.5 power and multiplying by distance results in an indication of the relative capacity of the system. Further, all other things being equal, a steel main of a given size is going to have more capacity than the same size plastic main because the additional strength of steel allows steel mains to be operated at higher pressures than plastic mains.

Schedule 2-3, Lines 43-73 details how the assignment of distribution mains was developed. These distribution mains exclude the mains that have been assigned to the Transmission function (12.75 percent) discussed in the prior section of this report. The distribution mains are summarized on Lines 44-56 of Schedule 2-3 from lowest to highest diameter. As shown on Line 48 of Schedule 2-3, the break point for distribution mains between transmission- and distribution-related facilities results in approximately 56% of the relative capacity being assigned to the distribution function with the remaining 44% of the relative capacity being assigned to the transmission function. This split results in 12.61% of the investment in the distribution mains function being assigned to the transmission function as shown on Line 59. The remaining 87.39% is assigned to the distribution function. The 12.61% is classified 50 percent demand or capacity and 50 percent commodity.

The break point between the transmission function and distribution function is such that the relative capacity of the mains classified as transmission approximately equals that of mains classified as distribution. This occurs between mains of 6 and 8 inches in diameter with mains of 8 inches or greater being assigned to the transmission function and the small diameters being assigned to the distribution function. This is roughly mid-way between the break point found the similar studies performed in the last rates cases for SourceGas and Black Hills/Aquila separately. In those studies, the SourceGas breakpoint was between 4 and 6 inches and for Black Hills/Aquila between 8 and 10 inches.

The 87.39% assigned to the distribution function is assigned between the customer and capacity functions based on examination of relative capacity and cost relationships contained in Schedule 2-3 that was used to determine the amount of distribution facilities assigned to the transmission function. The mains classified as distribution (87.39% of cost) are classified as capacity and customer. The portion classified as capacity is based on the unit cost of capacity of the 6-inch mains (the largest diameter, highest capacity distribution mains) which equals $0.54 per unit of capacity (feet times diameter to the 2.5 power). This results in 40.64% of the investment in distribution mains being classified as capacity-related and 59.36% as customer-related as shown on Lines 68 and 69 of Schedule 2-3.

The transmission-related portion of distribution mains equals 12.61% split equally between the commodity and capacity function resulting in 6.30% (12.61% x 50%) of the overall cost assigned to each function (Lines 60 and 61 of Schedule 2-3). The remaining 87.39% is split 40.64% to capacity and 59.36% to customer, resulting in 35.52% (87.39% x 40.64%) assigned to the capacity function and 51.88% (87.39% x 59.36%) assigned to the customer function (Lines 68 and 69 of Schedule 2-3). Combining the transmission and distribution functions for distribution mains results in 6.30% assigned to the commodity function, 41.82% (6.30% + 35.52%) assigned to the capacity function, and 51.88% assigned to the customer function as shown on Lines 71 through 73 of Schedule 2-3. These percentages apply to the 87.25 percent of Account 376 costs that are assigned to distribution facilities.

The overall classification of distribution mains compared to the classifications used in the last rate cases are as follows:

	Commodity	Capacity	Customer
Current Case	6.30%	41.82%	51.88%
Last BH/Aquila	5.99%	32.93%	61.08%
Last SourceGas	13.60%	40.70%	45.70%

The results from the current case appear reasonable when compared to the range from the prior cases. The amount classified as customer is roughly half-way between the two cases. Even though the legacy Black Hills/Aquila system serves significantly more customers, this is balanced by the fact that the legacy SourceGas system is much more rural and requires significantly more investment per customer. The Commodity assignment is within the range of the two legacy systems being slightly higher than the legacy Aquila system and the Capacity assignment slightly higher than the ranges of the two separate legacy systems.

Service Lines Weighting Factors Study

Plant investment in service lines (Account 380) is allocated to customer classes on the basis of the number of customers weighted to recognize relative differences in the unit investment cost in service lines used to connect customers in that class. The investment incurred to connect customers is a function of: 1) the average service line length and 2) the unit cost per foot. The unit cost per foot is primarily a function of the diameter of the service line required.

The analysis relies primarily on two sources of information. First, the Company's property records provide cost information regarding the various sizes of service lines. Second, the Company's Department of Transportation ("DOT") reports provide information regarding the number of service lines for each size. For the same reasons discussed above regarding mains, the original cost data should be restated in terms of current cost using Handy-Whitman indices for Account 380 - Services. Due to the fact that the property records have not always measured quantity in the same manner as the DOT reports for service lines. For example, in some instance quantity might be number of service lines rather than the cumulative feet of service lines installed. Therefore, we also consider the unit cost per foot for comparable size and material of mains.

In the past studies performed for the legacy Black Hills/Aquila and SourceGas systems, the methodology used to develop the weighting factors was the same; however, the weighting factors differed primarily due to differences in the classes of non-jurisdictional customers.

2009 Black Hills Service Lines Weighting Factors Study

The service lines weighting factors study used in the last legacy Black Hills/Aquila rate case was prepared in 2006 and used for the 2009 Nebraska rate case. In that study, the legacy Black Hills/Aquila class cost of service study contained the following customer classes and service lines weighting factors:

Customer Class	Service Line Weighting Factor
Residential	1.0
Commercial and Energy Options Firm	2.0
Energy Option Interruptible	2.5
Small Volume Interruptible	2.5
Large Volume Interruptible	5.0
Large Volume Joint and Firm	12.0
Transportation Firm and Interruptible	12.0

In the above table, the Residential, Commercial, and Energy Options Firm were the jurisdictional customer classes and the remaining classes were non-jurisdictional. The service lines weighting factors are used to develop the class allocation factors that are used for service lines and the customer component of mains.

2011 SourceGas Service Lines Weighting Factors Study

The service lines weighting factors study used in the last legacy SourceGas rate case was prepared in 2011 and used for the 2011 Nebraska rate case. On the legacy SourceGas system, the Company has historically not provided non-jurisdictional customers with a service line. In other words, the customers are directly served from the Company's transmission or distribution mains and the customer is responsible for the facilities needed to connect to the mains. Since the service lines weighting factor is typically used to also allocate the customer component of mains, the study performed for SourceGas developed separate weighting factors for service lines and the customer component of mains. In that study, the legacy SourceGas class cost of service study contained the following customer classes and service lines and customer component of mains weighting factors:

Customer Class	Service Line Weighting Factor	Customer Component of Mains Weighting Factor
Residential	1.0	1.0
Small Commercial	2.0	2.0
Large Commercial	5.0	5.0
Agricultural	0	3.0
Full Tariff	0	5.0
Negotiated - Distribution	0	5.0
Negotiated – Transmission	0	0
Super High Volume (Negotiated - Direct)	0	0

In the above table, the Residential, Small Commercial, and Large Commercial were the jurisdictional customer classes and the remaining classes were non-jurisdictional. As discussed earlier Negotiated – Transmission and the Super High Volume customers are served from the Company's or third-party transmission systems and thus are not allocated any distribution related costs and thus no customer component of mains.

Service Lines Customer Weighting Factors – Consolidated Black Hills Nebraska Gas System

The class cost of service study in the current case combines customers from the two systems into one set of relatively homogeneous groups of customers having common characteristics of each of the legacy customer classes. The proposed customer classes are as follows:

1. Residential – the consolidation of the existing legacy Residential classes
2. Commercial – the consolidation of the existing Commercial, Small Commercial, Large Commercial and Energy Options Firm classes
3. Agricultural – the existing legacy SourceGas Agricultural customers – these customers do not have service lines
4. Max. Rate – the consolidation of the existing non-jurisdiction Energy Options and the Full Tariff classes. Legacy SG customers do not have service lines.
5. Interruptible Sales – the existing legacy Black Hills/Aquila interruptible sales customers.
6. Negotiated Distribution – the consolidation of the existing Small and Large Volume and Negotiated Distribution classes. Legacy SG customers do not have service lines.
7. Negotiated Transmission – the consolidation of the existing Negotiated Transmission and Transportation classes served off Company transmission facilities.
8. Negotiated Direct – customers served off interstate pipelines
9. Negotiated Supply – these customers do not have service lines nor do they use any of the Company's facilities other than the pipe used to connect them to the Company's system

The analysis developing the customer class weighting factors used in the class cost of service study is summarized in Schedule 2-4. As shown in Lines 1 through 7 of Schedule 2-4, the first step is to determine the current cost of service lines by pipe diameter from information in the Company's property records and the resulting unit cost per foot. Next, the DOT reports were used to determine the number of service lines by pipe diameter and the average length of service lines. The DOT information was summarized into pipe diameter categories of 1 inch or less, 1-2 inches, 2-4 inches, and greater than 4 inches as shown in Column C and F, Lines 12-16. Next, the property record (both the service line data summarized in Schedule 2-4 and the comparable information for mains in Schedule 2-3) and DOT data are combined to estimate the unit cost and average service length of service lines for each of these sizes as shown on Lines 22-26 of Schedule 2-4. The number of service lines (Column D) is based on the DOT report and the total quantity in feet (Line 26, Column C) is also based on the total feet resulting from multiplying the average service line in the DOT report by the average service length (Column J, Lines 12-14). The average length for each service line was varied assuming longer service line lengths for higher diameter service lines to determine the quantity in feet of each service line. The total Trended Original Cost (TOC) on line 26 Column E closely approximates the TOC determined from the analysis of the Company's property records on Line 2 through 6. The TOC in Column E of the table on Line 22-26 is equal to the estimated quantity in feet (Column C) times the average cost per foot (Column F). The unit costs shown in Column F are based on both the unit costs shown on Lines 3 through 5 as well as the unit costs shown on Lines 20-26 of Schedule 2-3 (the mains analysis).

As shown in Lines 30 through 40 of Schedule 2-4, the next step is to allocate each size of service line to each proposed customer class based on the following assumptions based on consideration of the relative sizes of the average size customer in each class (Column D):

1. 95% of the Residential service lines are 1-inch or less, the remainder 1-2 inch.
2. Commercial service lines are assumed to be equally split between 1-inch or less and 1-2 inches.
3. Agricultural customers are not provided a service line.
4. 75% of the Maximum Rate legacy Aquila service lines are assumed to 1-2 inches and the remainder greater than 2 inches. The legacy SourceGas customers are not provided a service line.
5. 100% of the Interruptible Sales service lines are assumed to be 1-2 inches. All of these customers are legacy Aquila customers.
6. Negotiated Distribution service lines are assumed to be equally split between 1-2 inches and greater than 2 inches. The legacy SourceGas customers are not provided a service line.
7. The remaining customer classes are not served from service lines.

Next, the number of services lines allocated to each proposed customer class is multiplied by the applicable unit cost for each size service line, and the result is divided by the number of customers in each proposed customer class to determine an average unit cost for a service line per customer for each proposed customer class (Column L). A relative unit cost for each class is calculated as the ratio of that proposed customer class's unit cost relative to the unit cost of a Residential customer (Column M). These ratios are then used to assign weighting factors to each proposed customer class giving additional consideration to the relative size (use per customer) of a typical customer in each of the proposed customer classes (Column N).

Typically, the customer weighting factors developed for service lines are also used as the weighting factors for allocating costs assigned to the customer component of mains. Since the non-jurisdictional legacy SourceGas customers do not have Company provided service line, weighting factors for the customer component of mains need to recognize that these customers are responsible for their share of the customer component of mains. This consideration only effects the weighting factors for agricultural, Maximum Rate and Negotiated Distribution customers. The weighting for the Agricultural customers is set a level just above the jurisdictional Commercial customers recognizing the Agricultural customers are marginally larger and tend to be spaced further apart. The weighting factors for the Maximum Rate and Negotiated Distribution customer classes is based on assuming that the service line analysis includes all the customers in these classes not just the legacy Aquila customers.

The resulting proposed customer class service line weighting factors and customer component of mains weighting factors are as follows:

Customer Class	Service Line Weighting Factor	Customer Component of Mains Weighting Factor
Residential	1.0	1.0
Commercial	2.0	2.0
Agricultural	0	2.5
Maximum Rate	5.0	7.0
Interruptible Sales	3.0	3.0
Negotiated - Distribution	10.0	12.0
Negotiated – Transmission	0	0
Negotiated -Direct	0	0
Negotiated - Supply	0	0

These weighting factors are applied to the number of customers for each proposed customer class in the CCOSS to determine the service line and customer component of mains allocation bases for each proposed customer class. For example, a weighting factor of five means that the relative unit cost for that class is five times that of a Residential customer.

Meters and Regulators Weighting Factors Study

For purposes of cost allocation, the meters and regulators FERC Accounts 381 through 385 are combined. There are several reasons why this approach is reasonable. Typically, the meters and regulators are installed as a set and the assignment of the labor costs and the various piping components may be distributed through Accounts 381 through 384. In some cases, the cost of these installations may be split or allocated between Accounts 382 and 384; sometimes these accounts may not be used at all and these installation costs are booked to either Account 381 or 383. The approaches differ between utilities and may change over time within the same company (especially if the company is an amalgamation of acquisitions). Further, the accounting label of "industrial" for Account 385 is vague in the FERC Uniform System of Accounts especially compared to the definition of industrial that may be used in the development of rates. Furthermore, rates change over time and customers migrate between rates over time, but the plant accounting is not adjusted for this, nor would it be practical to do so. Finally, meters and regulators are fungible. Unlike piping, meters and regulators are commonly removed, rehabilitated or repaired, and then reinstalled in a different location. Based on all of these factors, it is most reasonable to treat Accounts 381 through 385 as a group and assign cost responsibility based on the installed cost of the entire meter and regulator set for each customer class regardless of where a customer's specific meter may be booked.

Plant investment in meters and regulators (Accounts 381 - 385) is allocated to customer classes on the basis of the number of customers weighted to recognize relative differences in the unit investment cost of the different types and sizes of meter and regulator sets used to connect customers in that class in a manner similar to that used to allocate service lines. The analysis primarily relies upon the data contained in the Company's property records which provides an inventory and original cost of each type and size of meter and regulator. For the same reasons discussed above regarding mains and service lines, the original cost data should be restated in terms of current cost using Handy-Whitman indices for meters and regulators.

The Company's plant accounting records contain sufficient detail to determine which meters are used for each proposed customer class. Handy-Whitman indices are used to restate the original cost of this data into current cost. Dividing the total current cost by the number of meters for each proposed customer class provides a unit cost per meter. In BH Nebraska Gas, most of the regulator inventory is not assigned to as specific size, thus the overall regulator trended cost divided by the overall meter trended cost provides the relative relationship of the regulator cost to the meter cost, and this is used to determine the amount of regulator related costs assigned to each proposed customer class's meter related cost. The meter and regulator set also includes an encoder-receiver-transmitter ("ERT") that is part of the automated meter reading system. This cost is also included in the estimated unit cost of each meter and regulator set for each proposed customer class. The total unit cost of a meter and regulator set for each proposed customer class is the summation of each of these components. According to the Company's records, some of the larger customers have more than one meter and regulator set, thus the unit cost per customer reflects the typical number of meter and regulator sets per customer. he relative unit cost is calculated for each proposed customer class as the ratio of that class's unit cost relative to the unit cost of a Residential customer. These ratios are then used to assign weighting factors to each proposed customer class, again with consideration also given to the relative size of a typical customer in each proposed customer class.

Schedule 2-5 shows the calculations discussed above and the resulting proposed customer class meters and regulators weighting factors are as follows:

Customer Class	Meter and Regulator Weighting Factor
Residential	1.0
Commercial	3.5
Agricultural	5.0
Maximum Rate	20
Interruptible Sales	10
Negotiated - Distribution	45
Negotiated – Transmission	75
Negotiated -Direct	120
Negotiated - Supply	15

These weighting factors are applied to the number of customers for each proposed customer class in the CCOSS to determine the meters and regulators allocation basis for each proposed customer class. For example, a weighting factor of 10 means that the relative unit cost for that class is 10 times that of a Residential customer.

Customer Accounting Weighting Factors

The Customer Accounting cost function includes operation and maintenance expenses booked to FERC Accounts 901 through 916 which include Customer Accounts Expenses, Customer Service and

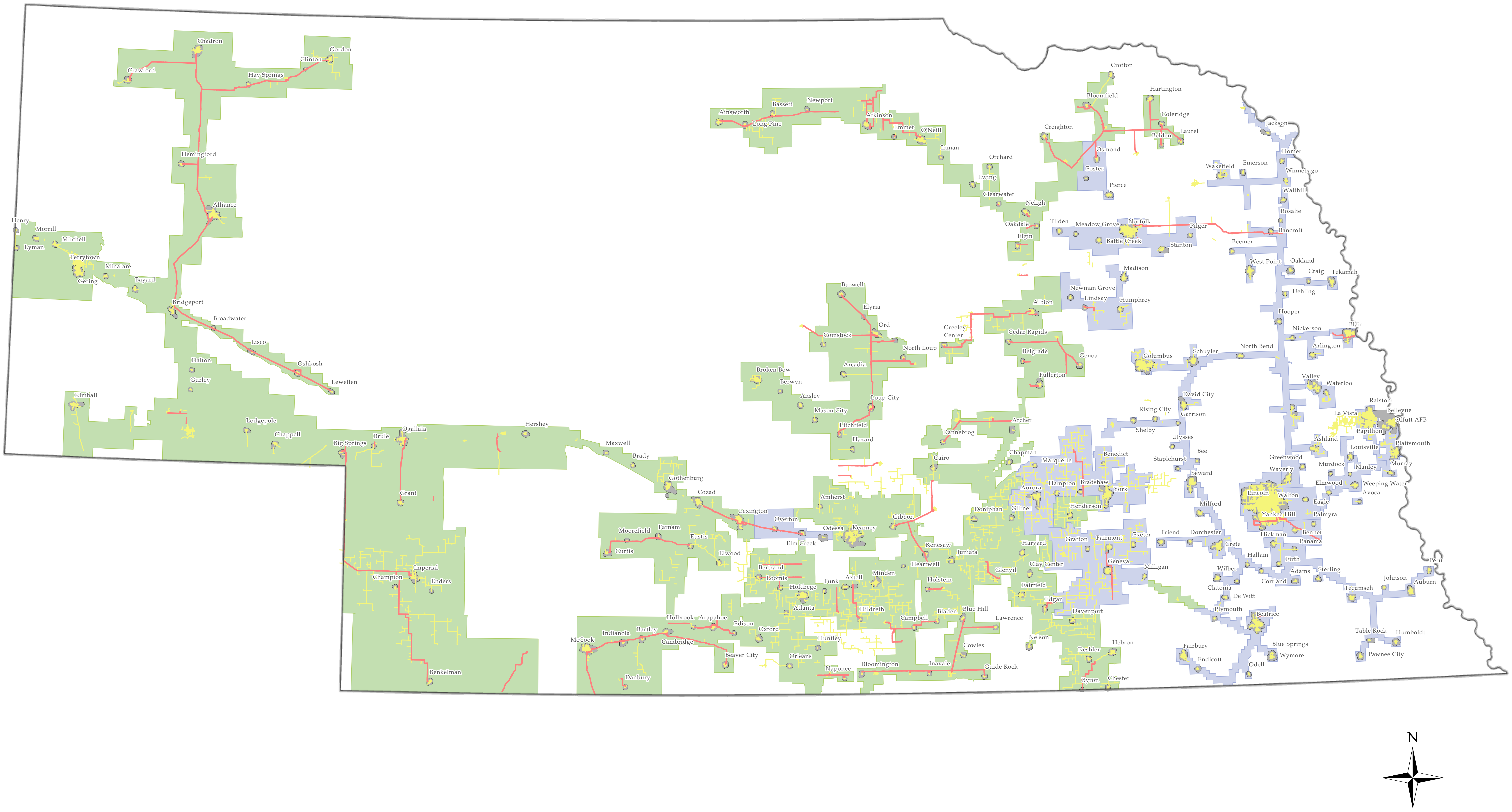
Information Expenses, and Sales Expenses. There are also other costs and revenues that are included in the Customer Accounting cost function as discussed earlier regarding the CCOSS.

The customer accounting weighting factors used reflect the relative cost of reading meters, customer accounting and billing, collections, and customer service for each of the customer classes. The following customer accounting weighting factors are used in the CCOSS:

Customer Class	Customer Accounting Weighting Factor
Residential	1.0
Commercial	1.5
Agricultural	1.5
Maximum Rate	5
Interruptible Sales	5
Negotiated - Distribution	10
Negotiated – Transmission	20
Negotiated -Direct	20
Negotiated - Supply	20

These weighting factors are comparable to the weighting factors used in the separate legacy SourceGas and Black Hills/Aquila rate cases. These weighting factors recognize that customer accounting services provided to the Residential, Commercial and Agricultural classes are comparable and that as the other non-jurisdictional customers become larger, the rates migrate from being standardized to becoming more customer specific negotiated rates and thus the services provided to these larger customers require higher levels of attention and service not only for connecting service but also maintaining communication with larger customers.

Exhibit TJS-2
Schedule 2-1



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0 50 Miles

Nebraska Rate Areas

Black Hills Energy

- 🟥 BHE Transmission
- 🟨 BHE Distribution
- 🟦 BH Gas Utility
- 🟩 BH Gas Distribution

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Black Hills Energy

Black Hills Nebraska Gas LLC
DOT/PHMSA Report Summary
Miles of Mains

Exhibit TJS-2
Schedule 2-2

	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]	[M]	[N]	[O]	[P]
		Total Miles			2018 by Pipe Size											
Line No.	Description	2016	2017	2018	2" or less	3-4"	5-8"	9-12"	Over 12"	Unkown	4" or less	6"	8"	10"	12"	Comment
1	SourceGas															
2	Transmission	1,212	1,219	1,219							983	211	25			Booked to Account 376
3	Steel	1,212	1,219	1,219							983	211	25			
4	Plastic	0	0	0												
5	Distribution	4,875	4,903	4,993	4,103	763	114	4	0	9						Booked to Account 376
6	Steel	3,336	3,336	3,379												
7	Plastic	1,539	1,567	1,615												
8	Black Hills/Aquila															
9	Transmission	44	44	92							0	0	61	0	31	Booked to Account 367
10	Steel	44	44	92							0	0	61	0	31	
11	Plastic	0	0	0												
12	Distribution	3,595	3,636	3,671	2,576	810	204	64	17	0						Booked to Account 376
13	Steel	1,872	1,869	1,866												
14	Plastic	1,723	1,767	1,805												
15	Total															
16	Transmission	1,256	1,263	1,311							983	211	86	0	31	
17	Steel	1,256	1,263	1,311							983	211	86	0	31	
18	Plastic	0	0	0												
19	Distribution	8,470	8,539	8,664	6,679	1,573	318	68	17	9						
20	Steel	5,208	5,205	5,245												
21	Plastic	3,262	3,334	3,420												

Black Hills Nebraska Gas, LLC
Mains Classifation Study
Test Year Ending December 31, 2019

Attachment TJS-2
Schedule 2-3

	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]
Line No.	Description	Diameter	Original Cost	Length	Relative Capacity	Cumulative Relative Capacity	Trended Original Cost	Trended Cost per Foot	TOC per Capacity Unit	Cumulative Trended Original Cost
		Inches	$	Feet			$	$/ft		
					(1)			(2)	(3)	
1	Transmission Mains - Account 367									
2	Steel	2	31,133	415			33,715	81.24		
3	Steel	6	26,794	2,851			84,707	29.71		
4	Steel	8	1,451,047	66,158			4,276,470	64.64		
5	Steel	10	347	105			1,110	10.57		
6	Steel	12	3,998,469	165,167			26,890,058	162.81		
7	Subtotal Transmission		5,507,791	234,696			31,286,060			
8	NEGD Transmission Mains - Account 376 - Per DOT									
9	Steel - 4" or Less			5,188,603						
10	2"			3,487,675			44,966,067	12.89		
11	3"			867,928			13,613,341	15.68		
12	4"			833,000			21,457,048	25.76		
13	Steel - 6"			1,116,456			32,914,994	29.48		
14	Steel - 8"			132,475			8,192,479	61.84		
15	Total NEGD Transmission Mains			6,437,534			121,143,929			
16	Assignmnet of Account 376 to Transmission						121,143,929			**12.75%**
17	Capacity						50.00%			6.38%
18	Commodity						50.00%			6.38%
19	Distribution Mains - Account 376									
20	Plastic	1	4,775,433	228,185			5,335,334	23.38		
21	Plastic	2	83,362,680	14,348,952			132,277,034	9.22		
22	Plastic	3	2,918,962	319,670			5,138,793	16.08		
23	Plastic	4	40,318,927	2,807,238			54,544,380	19.43		
24	Plastic	6	13,160,192	460,680			14,926,823	32.40		
25	Plastic	8	123,100	898			136,731	152.26		
26	Plastic	10	59,523	433			73,249	169.17		
27	Subtotal Distribution		144,718,815	18,166,056			212,432,343			
28	Steel	1	1,257,672	157,902			3,438,406	21.78		
29	Steel	2	78,577,982	20,204,169			326,427,069	16.16		
30	Steel	3	13,499,419	3,942,116			72,354,945	18.35		
31	Steel	4	41,218,142	4,603,729			146,068,409	31.73		
32	Steel	6	20,384,404	1,902,934			76,916,714	40.42		
33	Steel	8	17,999,636	688,491			37,597,929	54.61		
34	Steel	10	1,414,715	110,589			7,931,244	71.72		
35	Steel	12	28,493,895	213,231			34,360,319	161.14		
36	Steel	14	440	126			655	5.20		
37	Steel	16	14,383,321	36,374			16,416,331	451.32		
38	Steel	18	276,179	31,796			5,822,073	183.11		
39	Steel	20	324,210	20,845			5,135,150	246.35		
40	Steel	24	411,093	24,099			5,212,399	216.29		
41	Subtotal Distribution		218,241,108	31,936,401			737,681,643			
42	Total Distribution Mains - Account 376		362,959,923	50,102,457			950,113,986			

Black Hills Nebraska Gas, LLC
Mains Classifation Study
Test Year Ending December 31, 2019

Attachment TJS-2
Schedule 2-3

	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]
Line No.	Description	Diameter	Original Cost	Length	Relative Capacity	Cumulative Relative Capacity	Trended Original Cost	Trended Cost per Foot	TOC per Capacity Unit	Cumulative Trended Original Cost
		Inches	$	Feet			$	$/ft		
43	Net Mains - Accounts 376 (excl NEGD Transmission)			43,664,923			828,970,056			**87.25%**
44	Plastic & Steel	1		386,087	386,087	0.04%	8,773,740	22.72	$22.72	1.06%
45	Plastic & Steel	2		31,065,446	175,732,702	18.01%	413,738,036	13.32	$2.35	50.97%
46	Plastic & Steel	3		3,393,858	52,905,003	23.41%	63,880,396	18.82	$1.21	58.67%
47	Plastic & Steel	4		6,577,967	210,494,955	44.94%	179,155,741	27.24	$0.85	80.29%
48	Plastic & Steel	6		1,247,158	109,976,426	56.18%	58,928,542	47.25	$0.54	87.39%
49	Plastic & Steel	8		556,914	100,812,166	66.49%	29,542,180	53.05	$0.29	90.96%
50	Plastic & Steel	10		111,022	35,108,239	70.07%	8,004,492	72.10	$0.23	91.92%
51	Steel	12		213,231	106,366,155	80.95%	34,360,319	161.14	$0.32	96.07%
52	Steel	14		126	92,404	80.96%	655	5.20	$0.01	96.07%
53	Steel	16		36,374	37,246,976	84.77%	16,416,331	451.32	$0.44	98.05%
54	Steel	18		31,796	43,707,277	89.24%	5,822,073	183.11	$0.13	98.75%
55	Steel	20		20,845	37,288,670	93.05%	5,135,150	246.35	$0.14	99.37%
56	Steel	24		24,099	68,002,852	100.00%	5,212,399	216.29	$0.08	100.00%
57	Total Distribution			43,664,923	978,119,912		828,970,056			
58	**Classification of Distribution (Account 376)**									
59	Total 8 inches and Over - Transmission Function			994,407	327,812,572		104,493,600			12.61%
60	Capacity Assignment				50%					6.30%
61	Commodity Assignment				50%					6.30%
62	Total 6 inches and Less - Distribution			42,670,516	549,495,173		724,476,456			87.39%
63	Distribution Capacity/Customer Assignment									
64	Relative Capacity of less than 8 inches				549,495,173	Column E, Line 62				
65	Unit TOC per Capacity of 6 inch				0.54	Column I, Line 48				
66	TOC of less than 8 inch that is Capacity Related				294,435,368	Line 64 times Line 65				
67	TOC of less than 8 inches				724,476,456	Sum on Column G, Lines 44 through 48				
68	Capacity Assigment				40.64%	Line 66 / Line 67				35.52%
69	Customer Assignement				59.36%	1 minus Line 68				51.88%
70	Distribution Assignment of Account 376 (excl NEGD Transmission)									**87.25%**
71	Commodity				6.30%	Column J, Line 61				5.50%
72	Capacity				41.82%	Column J Line 60 plus Column J Line 68				36.49%
73	Customer				51.88%	Column J Line 69				45.26%
74	Overall Asssignment of Account 376 (incl. NEGD Transmssion)									
75	Commodity									11.87%
76	Capacity									42.86%
77	Customer									45.26%
78	(1) Diameter (Column B) to the 2.5 power times length (Column D)									
79	(2) Trended Original Cost (Column G) divided by length (Column D).									
80	(3) Trended Original Cost (Column G) divided by relative capacity (Column E).									

Black Hills Nebraska Gas, LLC
Service Lines Weighting Factor Study
Base Year Ending December 31, 2019

Attachment TJS-2
Schedule 2-4

[A] [B] [C] [D] [E] [F] [G] [H] [I] [J] [K] [L] [M] [N]

Line No.

1 **Property Data**

Line No.	Company	Diam	Quantity	Book Cost	TOC	ve Cost/Foot
2	Black Hills Nebraska Gas, LLC	Unknown	20,013	$20,967,308	$42,317,874	$2,114.50
3	Black Hills Nebraska Gas, LLC	1" or less	9,416,310	$102,889,404	$161,563,970	$17.16
4	Black Hills Nebraska Gas, LLC	>1" thru 2"	441,436	$6,022,990	$8,299,345	$18.80
5	Black Hills Nebraska Gas, LLC	>2" thru 4"	38,059	$558,830	$878,853	$23.09
6	Black Hills Nebraska Gas, LLC	>4" thru 8"	23	$34	$77	$3.33
7		**Totals**	**9,915,841**	**130,438,567**	**213,060,118**	**$21.49**

(Header row is line 2.)

8

9 **2018 DOT Report - Number of Services** **2018 DOT Report Summary**

10

Line No.	Company	Diam	DOT Number of Services	Diameter	DOT Number of Service Lines	**2018 PHMSA Report**	
12	**Black Hills Nebraska Gas, LLC**	Unknown	6,790	1" or less	258,071	Total Services	312,881
13		1" or less	258,071	>1" thru 2"	47,630	Avg Serv Length	55
14		>1" thru 2"	47,630	> 2"	390	Number of feet	17,052,015
15		>2" thru 4"	380	**Total**	**306,091**		
16		>4" thru 8"	10	Unknown	6,790		
17				**Total w/Unknown**	**312,881**		

(Header row is line 11.)

18
19
20 **Average Cost**
21

Line No.	Diameter	Quantity - ft	Quantity - #	TOC	Ave Cost per Foot	Average Length	Average Cost/ Customer
23	1	13,500,000	264,861	135,000,000	$10.00	51.0	$509.70
24	1-2	3,500,000	47,630	70,000,000	$20.00	73.5	$1,469.66
25	2+	100,000	390	3,500,000	$35.00	256.4	$8,974.36
26	**Totals**	**17,100,000**	**312,881**	**$208,500,000**			

(Header row is line 22.)

27
28 **Customer Class Weighting Factors**
29

Line No.	Customer Class	Number of Customers	Test Year Volumes Therms	Use per Customer	Number of Service Lines	Percent 1" or less	Percent >1" thru 2"	Percent > 2"	1" or less	>1" thru 2"	> 2"	Unit Cost/ Customer	Relative Unit Cost	Weighting Factor
31	Residential	255,678	178,400,064	698	255,678	95%	5%		242,894	12,784		$557.70	1.00	1.00
32	Commercial	32,393	126,241,584	3,897	32,393	50%	50%		16,197	16,197		$989.68	1.77	2.00
33	Agricultural	8,838	41,002,809	4,639	0									
34	Maximum Rate	136	17,846,413	131,224	100		75%	25%		75	25	$2,473.37	4.43	5.00
35	Interruptible Sales	142	2,504,692	17,639	142		100%	0%		142	0	$1,469.66	2.64	3.00
36	Negotiated Distribution	128	115,151,356	899,620	120		50%	50%		60	60	$4,895.63	8.78	10.00
37	Negotiated Transmission	9	77,744,660	8,638,296	0									
38	Negotiated Direct	15	227,159,630	15,143,975	0									
39	Negotiated Supply	2	0	0	0									
40	**Totals**	**297,341**	**786,051,207**		**288,433**				**259,091**	**29,257**	**85**			

(Header row is line 30.)

Black Hills Nebraska Gas, LLC
Meters Weighting Factor Study
Base Year Ending December 31, 2019

Exhibit TJS-2
Schedule 2-5

	A	**B**	**C**	**D**	**E**	**F**	**G**	**H**	**I**	**J**	**K**	**L**
						Unit Cost of Meter and Regulator Set						
Line No.	**Customer Class**	**Average Number of Bills**	**Meters**	**Booked Cost**	**TOC**	**Meter**	**Regulators**	**Total Meters & Regulators**	**Meter per Customer**	**Total Meter Installation per Customer**	**Relative Cost**	**Weighting Factor**
1	Residential	255,678	253,816	$23,156,789	$47,786,921	$188	$149	$338	1.0	$338	1.0	1.0
2	Commercial	32,393	32,587	$9,882,412	$21,426,215	$658	$521	$1,179	1.0	$1,179	3.5	3.5
3	Agricultural	8,838	9,400	$3,756,197	$8,465,567	$901	$714	$1,615	1.0	$1,615	4.8	5.0
4	Maximum Rate	136	179	$298,768	$630,974	$3,525	$2,795	$6,320	1.0	$6,320	18.7	20.0
5	Interruptible Sales	142	152	$159,234	$297,056	$1,954	$1,550	$3,504	1.0	$3,504	10.4	10.0
6	Negotiated Distribution	128	266	$525,796	$1,053,524	$3,961	$3,141	$7,101	2.0	$14,202	42.1	45.0
7	Negotiated Transmission	9	15	$56,362	$105,135	$7,009	$5,558	$12,567	2.0	$25,133	74.5	75.0
8	Negotiated Direct	15	64	$123,297	$362,663	$5,667	$4,493	$10,160	4.0	$40,639	120.4	120.0
9	Negotiated Supply	0	3	$3,000	$5,747	$1,916	$1,519	$3,435	1.5	$5,152	15.3	15.0
10	**Totals**	**297,339**	**296,482**	**$37,961,856**	**$80,133,803**							
11												
12												
13	**Retirement Unit**		**Quantity**	**Booked Cost**	**TOC**							
14	Meter Bar Regulator Assembly-<2"		90,981	$30,745,351	$35,963,721							
15	Meter Bar Regulator Assembly->=3"		5	$106,846	$130,069							
16	Meter Bar Regulator Assembly-2"		2,117	$1,492,564	$1,495,551							
17	Regulator, Gas - Less Than 2"		59,013	$5,873,834	$7,811,926							
18	Regulator, Gas - 2"		1,226	$2,563,907	$2,767,206							
19	Regulator, Gas - >=3"		119,947	$367,075	$14,920,074							
20	Regulator, Gas - Not Available		36	$8,572,253	$452,119							
21	**Totals**		**273,325**	**$49,721,828**	**$63,540,666**							
22												
23	Regulator as a Percent of Meter				79.29%							

Exhibit No. TJS-3
Historical Number of Customers
Page 1 of 1

SourceGas Distribution LLC- Nebraska
Summary of Historical Billing Determinants
Twelve Months Ended March 31, 2011

Exhibit__(TJS-4)

	[A]		[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]
		Twelve Months Ended March 31											
Line No.	**Description**	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**
1	**1. Residential**												
2	Number of Bills	959,891	953,933	941,967	930,784	921,378	907,348	880,360	878,527	857,642	856,822	834,309	815,322
3	Average # of Monthly Bills	79,991	79,494	78,497	77,565	76,782	75,612	73,363	73,211	71,470	71,402	69,526	67,944
4	Volumes- (Therms)	65,673,398	74,918,185	63,966,081	66,420,907	61,629,671	54,657,455	51,669,014	54,648,491	51,726,539	51,251,153	53,499,332	48,851,754
5	Use per Customer	821	942	815	856	803	723	704	746	724	718	769	719
6	**2. Small Commerical**												
7	Number of Bills	138,377	136,864	135,534	134,583	134,804	133,724	130,525	130,790	126,005	125,473	120,302	121,443
8	Average # of Monthly Bills	11,531	11,405	11,295	11,215	11,234	11,144	10,877	10,899	10,500	10,456	10,025	10,120
9	Volumes- (Therms)	15,642,932	19,140,232	15,682,702	16,750,545	16,009,687	14,328,060	14,244,290	15,639,950	15,348,332	15,602,038	17,082,605	15,819,802
10	Use per Customer	1,357	1,678	1,389	1,494	1,425	1,286	1,310	1,435	1,462	1,492	1,704	1,563
11	**3. Large Commerical**												
12	Number of Bills	20,356	21,215	21,513	21,108	19,667	18,764	17,640	17,809	18,123	17,999	17,906	17,819
13	Average # of Monthly Bills	1,696	1,768	1,793	1,759	1,639	1,564	1,470	1,484	1,510	1,500	1,492	1,485
14	Volumes- (Therms)	25,072,659	29,468,953	27,973,826	27,171,669	25,240,068	23,310,977	22,290,429	25,457,414	25,215,846	25,307,039	27,303,469	25,921,414
15	Use per Customer	14,781	16,669	15,604	15,447	15,400	14,908	15,164	17,154	16,696	16,872	18,298	17,456
16	**4. Total Residential and Commercial**												
17	Number of Bills	1,118,624	1,112,012	1,099,014	1,086,475	1,075,849	1,059,836	1,028,525	1,027,126	1,001,770	1,000,294	972,517	954,584
18	Average # of Monthly Bills	93,219	92,668	91,585	90,540	89,654	88,320	85,710	85,594	83,481	83,358	81,043	79,549
19	Volumes- (Therms)	106,388,989	123,527,370	107,622,609	110,343,121	102,879,426	92,296,492	88,203,733	95,745,855	92,290,717	92,160,230	97,885,406	90,592,970
20	Use per Customer	1,141	1,333	1,175	1,219	1,148	1,045	1,029	1,119	1,106	1,106	1,208	1,139
21	**5. Agricultural**												
22	Number of Bills	121,962	119,768	114,131	111,193	108,813	101,733	94,696	92,754	86,074	87,218	84,355	84,419
23	Average # of Monthly Bills	10,164	9,981	9,511	9,266	9,068	8,478	7,891	7,730	7,173	7,268	7,030	7,035
24	Volumes- (Therms)	56,816,159	81,201,961	67,955,575	91,461,402	77,536,930	61,329,559	44,501,997	44,335,927	32,847,106	38,372,096	57,864,671	30,389,317
25	Use per Customer	5,590	8,136	7,145	9,871	8,551	7,234	5,639	5,736	4,579	5,279	8,232	4,320

Exhibit No. TJS-4
Summary of Competing Electric Utility
Residential & Commercial Rates
Page 1 of 1

Black Hills Nebraska Gas
Rates of Competing Electric Utilities - Nebraska

Line No.	[A] Utility	[B] Number of Black Hills Customers	[C] Customer / Fixed Charge	[D] Winter Lowest Block	[E] Other Blocks
			$/Month	$/kWh	$/kWh
1	Lincoln Electric System	100,520			
2	Residential		23.00-50.00	0.0548	0.0801
3	General Service		23.10-58.00	0.0585-0.0606	0.0880-0.0908
4	Heating Service		37.75-275.00	0.0480-0.0493	0.0776-0.0805
5	Nebraska Public Power District	57,969			
6	Residential		22.50	0.0622	0.0808-0.1013
7	General Service		32.50-48.50	0.0733	0.0973
8	Commercial Electric Heat		54.00-72.50	0.0372	0.0477-0.1274
9	Omaha Public Power District	48,352			
10	Residential		30.00	0.0527	0.0746-0.0936
11	Residential Conservation		30.00	0.0431	0.0746-0.0936
12	General Service		33.00	0.0524	0.0789-0.0911
13	City of Columbus	5,185			
14	Residential		10.70	0.0724-0.0873	0.0724-0.0873
15	Commercial		60.35	0.1055	0.1055
16	City of Beatrice	4,549			
17	Residential		10.00	0.0727	0.1028
18	Residential Space Heating		10.00	0.0500	0.1028
19	General Service		18.00	0.0834	0.1143
20	General Service - Electric Heat		18.00	0.0533	0.1143
21	Southern Public Power District	4,566			
22	Residential		23.00	0.0725	0.0915
23	Residential Total Electric		23.00	0.0670	0.0725-0.0915
24	General Service		23.00	0.0820	0.0890
25	General Service Total Electric		23.00	0.0625	0.082-0.089
26	City of Gering	3,446			
27	Residential		29.70	0.1020	0.1250-0.1970
28	Commercial		30.30-34.50	0.1080	0.1280-0.2350
29	City of Alliance	3,438			
30	Residential		22.00-30.00	0.0837	0.1087
31	General Service		25.50-70.00	0.10826-0.11597	0.10826-0.11597
32	City of Sidney	3,069			
33	Residential		20.00	0.0900	0.0985
34	Residential All Electric		20.00	0.0750	0.0985
35	General Service		35.00	0.1070	0.1070
36	General Service All Electric		35.00	0.0750	0.1070
37	Norrris Public Power District	2,575			
38	Residential		17.50-26.00	0.0665-0.0685	0.0820-0.0935
39	Small Commercial		26.00	0.0813	0.1008
40	General Service		26.00	0.0700-0.0813	0.1000-0.1008
41					
42	Total	233,669			
43					
44	Total Black Hills Customers	290,698			
45					
46	Percentage	80%			

Lincoln Electric System
LES Administrative Board Resolution: A-91932 Schedule Issued January 1, 2020
City Council Resolution: 2019-13 Effective with all bills rendered after December 31, 2019

Sheet 1 of 2

Schedule RS - RESIDENTIAL SERVICE - 01 (Standard) & 03 (with Electric Heating)

AVAILABLE: Within Lincoln, Nebraska, and the LES Service Area.

APPLICABLE: To single family residences and individually metered apartments.

CHARACTER OF SERVICE: Single-phase, or three-phase if available, 60 Hertz alternating current, supplied at LES' standard voltages through an LES-owned meter.

BILL: Customer Charge + Facilities Charge + Energy Charge + All Riders (if applicable) + Service Fees (if applicable) + City Dividend for Utility Ownership + Sales Tax (if applicable); based on the RATE in effect and LES' Service Regulations. Plus, for BILLING PERIODS less than 27 days, on the CUSTOMER'S first and final BILLS, a per day credit times the difference between 30 and the actual number of days in the BILLING PERIOD.

BILLING PERIOD: Bills are rendered on the basis of the scheduled meter reading dates or a date agreeable with LES for final readings. Under normal conditions, BILLING PERIODS typically range from 27 to 35 days.

SEASONAL PROVISION: Summer and winter periods are defined as:

Summer – The four-month period from June 1 through September 30
Winter – The eight-month period from October 1 through May 31

Energy Charges on the BILL will be prorated between seasons in transitional months (i.e., June and October) according to the number of days corresponding to each season covered by the BILL.

RATE:

RESIDENTIAL	Summer	Winter
Customer Charge $/BILL	$5.00	
Facilities Level 1 Charge $/BILL	$18.00	
Less than 27 day billing period credit Level 1 $/day (first & final bills)	$0.60	
Facilities Level 2 Charge $/BILL	$26.00	
Less than 27 day billing period credit Level 2 $/day (first & final bills)	$0.87	
Facilities Level 3 Charge $/BILL	$40.00	
Less than 27 day billing period credit Level 3 $/day (first & final bills)	$1.33	
Facilities Charge Three Phase $/BILL	$45.00	
Less than 27 day billing period credit Three Phase $/day (first & final bills)	$1.50	
Energy Charge $/kWh	$0.0801	$0.0548

Lincoln Electric System
LES Administrative Board Resolution: A-91932 Schedule Issued January 1, 2020
City Council Resolution: 2019-13 Effective with all bills rendered after December 31, 2019

Sheet 2 of 2

Schedule RS - RESIDENTIAL SERVICE - 01 (Standard) & 03 (with Electric Heating)

FACILITIES LEVEL: Facilities Charges are based on average monthly energy for bills rendered during the twelve-month period of December 1 through November 30. LES will assign CUSTOMERS to the applicable Facilities Level. Newly constructed single family dwelling services, with no prior energy usage history, will initially be assigned to Level 2. Newly constructed multi-family dwelling services, with no prior energy usage history, will initially be assigned to Level 1. Levels are reviewed and changed as necessary each January 1. Exceptions to the below thresholds for Facilities Level assignments will only be made in rare instances and with the approval of LES.

Level 1 – Average monthly energy less than 800 kWh
Level 2 – Average monthly energy 800 kWh to 1,500 kWh
Level 3 – Average monthly energy greater than 1,500 kWh

RESIDENTIAL ELECTRIC HEATING WITH SECOND METER: Existing residential CUSTOMERS, where service has been provided for electric heating purposes only and is metered on a separate circuit, shall have energy use from these two services combined into one BILL. This type of electric heating service is only available to existing services and is not available for application to new service requests.

TERMS AND CONDITIONS:

1. Service will be furnished subject to LES' policies and Service Regulations.
2. TERMS OF PAYMENT - BILLS on active accounts are due in full 23 days after rendered. BILLS on final accounts are due upon receipt or the date of the most recently issued BILL, whichever is later. Any past due amounts are subject to LES policies regarding termination of electric service and applicable Service Fees. Charges are subject to all applicable State and Local sales tax.
3. FLUCTUATING LOADS AND HARMONICS – CUSTOMERS operating equipment causing harmonic currents and/or highly fluctuating or large instantaneous demands, including, but not limited to, variable speed drives, motor starting, welders and X-ray machines, shall be required to pay all nonbetterment costs of corrective action required to maintain acceptable service quality to the CUSTOMER and not interfere with service on LES' lines or to other CUSTOMERS. See System Disturbances and Service Disruptions, and Disconnection of Electric Service in the Service Regulations.
4. COGENERATION OR SMALL POWER PRODUCTION - Refer to Customer-Owned Generation in the Service Regulations.

Lincoln Electric System
LES Administrative Board Resolution: A-91932 Schedule Issued January 1, 2020
City Council Resolution: 2019-13 Effective with all bills rendered after December 31, 2019

Sheet 1 of 2

Schedule GS - GENERAL SERVICE - 10 (Secondary) & 13 (Primary)

AVAILABLE: Within Lincoln, Nebraska, and the LES Service Area.

APPLICABLE: A CUSTOMER will receive service on this schedule if the following conditions are met:

a. Energy usage does not exceed 25,000 kWh per BILLING PERIOD for each of nine consecutive BILLING PERIODS, and
b. The CUSTOMER'S demand does not exceed 100 kW in two summer BILLING PERIODS including the current BILLING PERIOD and all BILLING PERIODS in the preceding 11 months.
c. For new CUSTOMER accounts, usage and demand projections will be prepared by LES' Energy Delivery Division and the account will be placed on the appropriate schedule.
d. OUTDOOR RECREATIONAL LIGHTING, as defined in the TERMS AND CONDITIONS, is not subject to the limitation of (b) above.

CHARACTER OF SERVICE: Single-phase, or three-phase if available, 60 Hertz alternating current, supplied at LES' standard voltages through an LES-owned meter.

BILL: Customer Charge + Facilities Charge + Energy Charge + All Riders (if applicable) + Service Fees (if applicable) + City Dividend for Utility Ownership + Sales Tax (if applicable); based on the RATE in effect and LES' Service Regulations. Plus, for BILLING PERIODS less than 27 days, on the CUSTOMER'S first and final BILLS, a per day credit times the difference between 30 and the actual number of days in the BILLING PERIOD.

BILLING PERIOD: Bills are rendered on the basis of the scheduled meter reading dates or a date agreeable with LES for final readings. Under normal conditions, BILLING PERIODS typically range from 27 to 35 days.

SEASONAL PROVISION: Summer and winter periods are defined as:

Summer – The four-month period from June 1 through September 30
Winter – The eight-month period from October 1 through May 31

Energy Charges on the BILL will be prorated between seasons in transitional months (i.e., June and October) according to the number of days corresponding to each season covered by the BILL.

Lincoln Electric System

LES Administrative Board Resolution: A-91932 Schedule Issued January 1, 2020
City Council Resolution: 2019-13 Effective with all bills rendered after December 31, 2019

Sheet 2 of 2

Schedule GS - GENERAL SERVICE - 10 (Secondary) & 13 (Primary)

RATE:

GENERAL SERVICE	Summer	Winter
Customer Charge $/BILL	$6.50	
Facilities Charge $/BILL	$16.60	
Less than 27 day billing period credit $/day (first & final bills)	$0.55	
Facilities Charge Three Phase $/BILL	$51.50	
Less than 27 day billing period credit Three Phase $/day (first & final bills)	$1.72	
Facilities Charge Primary $/BILL	$28.50	
Less than 27 day billing period credit Primary $/day (first & final bills)	$0.95	
Energy Charge Secondary $/kWh	$0.0908	$0.0606
Energy Charge Primary $/kWh	$0.0880	$0.0585

PRIMARY VOLTAGE DELIVERY: Where the CUSTOMER takes service and is metered at an available LES standard primary distribution voltage of either 7,200/12,470 volts three phase, four wire or 34,500 volts three phase, three wire; and the CUSTOMER owns, operates and maintains all voltage transformation and other distribution equipment past the primary meter.

TERMS AND CONDITIONS:

1. Service will be furnished subject to LES' policies and Service Regulations.
2. TERMS OF PAYMENT - BILLS on active accounts are due in full 23 days after rendered. BILLS on final accounts are due upon receipt or the date of the most recently issued BILL, whichever is later. Any past due amounts are subject to LES policies regarding termination of electric service and applicable Service Fees. Charges are subject to all applicable State and Local sales tax.
3. FLUCTUATING LOADS AND HARMONICS – CUSTOMERs operating equipment causing harmonic currents and/or highly fluctuating or large instantaneous demands, including, but not limited to, variable speed drives, motor starting, welders and X-ray machines, shall be required to pay all nonbetterment costs of corrective action required to maintain acceptable service quality to the CUSTOMER and not interfere with service on LES' lines or to other CUSTOMERS. See System Disturbances and Service Disruptions, and Disconnection of Electric Service in the Service Regulations.
4. COGENERATION OR SMALL POWER PRODUCTION - Refer to Customer-Owned Generation in the Service Regulations.
5. OUTDOOR RECREATIONAL LIGHTING is metered service to off-peak, dusk-to-dawn area lighting for outdoor recreational facilities. OUTDOOR RECREATIONAL LIGHTING service must be wired and metered separate from any use other than OUTDOOR RECREATIONAL LIGHTING so that only OUTDOOR RECREATIONAL LIGHTING fixtures are on this metered circuit.

Lincoln Electric System
LES Administrative Board Resolution: A-91932 Schedule Issued January 1, 2020
City Council Resolution: 2019-13 Effective with all bills rendered after December 31, 2019

Sheet 1 of 2

Schedule HS - HEATING SERVICE - 21 (Secondary) & 23 (Primary)

AVAILABLE: Within Lincoln, Nebraska, and the LES Service Area.

APPLICABLE: To any nonresidential CUSTOMER for space heating and/or approved water heating installations where this Heating Service is supplied through a separately metered circuit. For the Heating Service, summer demands shall not exceed the highest winter demand of the past 12 months. An exception to this demand requirement is a geothermal or air-to-air heat pump space conditioning system.

A Heating Service CUSTOMER will receive the Large Heating Service classification if that CUSTOMER'S energy usage is greater than 25,000 kWh per BILLING PERIOD for two BILLING PERIODS, including the current BILLING PERIOD and all BILLING PERIODS in the preceding 11 months.

Removal from the Large Heating Service classification will occur when the CUSTOMER'S energy usage fails to exceed 25,000 kWh per BILLING PERIOD for 12 consecutive months.

CHARACTER OF SERVICE: Single-phase, or three-phase if available, 60 Hertz alternating current, supplied at LES' standard voltages through an LES-owned meter.

BILL: Customer Charge + Facilities Charge + Energy Charge + All Riders (if applicable) + Service Fees (if applicable) + City Dividend for Utility Ownership + Sales Tax (if applicable); based on the RATE in effect and LES' Service Regulations. Plus, for BILLING PERIODS less than 27 days, on the CUSTOMER'S first and final BILLS, a per day credit times the difference between 30 and the actual number of days in the BILLING PERIOD.

BILLING PERIOD: BILLS are rendered on the basis of the scheduled meter reading dates or a date agreeable with LES for final readings. Under normal conditions, BILLING PERIODS typically range from 27 to 35 days.

SEASONAL PROVISION: Summer and winter periods are defined as:

Summer – The four-month period from June 1 through September 30
Winter – The eight-month period from October 1 through May 31

Energy Charges on the BILL will be prorated between seasons in transitional months (i.e., June and October) according to the number of days corresponding to each season covered by the BILL.

Lincoln Electric System
LES Administrative Board Resolution: A-91932 Schedule Issued January 1, 2020
City Council Resolution: 2019-13 Effective with all bills rendered after December 31, 2019

Sheet 2 of 2

Schedule HS - HEATING SERVICE - 21 (Secondary) & 23 (Primary)

RATE:

HEATING SERVICE	Summer	Winter
Customer Charge $/BILL	$5.30	
Facilities Charge $/BILL	$32.45	
Less than 27 day billing period credit $/day (first & final bills)	$1.08	
Facilities Charge Three Phase $/BILL	$129.70	
Less than 27 day billing period credit Three Phase $/day (first & final bills)	$4.32	
Facilities Charge Large $/BILL	$269.70	
Less than 27 day billing period credit Large $/day (first & final bills)	$8.99	
Facilities Charge Primary $/BILL	$254.70	
Less than 27 day billing period credit Primary $/day (first & final bills)	$8.49	
Energy Charge Secondary $/kWh	$0.0805	$0.0493
Energy Charge Primary $/kWh	$0.0776	$0.0480

TERMS AND CONDITIONS:

1. Service will be furnished subject to LES' policies and Service Regulations.
2. TERMS OF PAYMENT - BILLS on active accounts are due in full 23 days after rendered. BILLS on final accounts are due upon receipt or the date of the most recently issued BILL, whichever is later. Any past due amounts are subject to LES policies regarding termination of electric service and applicable Service Fees. Charges are subject to all applicable State and Local sales tax.
3. The installation of the main disconnect, meter socket and other equipment required to accept service under this schedule (except the Meter), shall be arranged and paid for by the CUSTOMER.
4. When the same permanently installed all-electric equipment is used for both heating and cooling, such as a heat pump (and certain other combination units upon specific approval) this rate schedule shall apply.
5. FLUCTUATING LOADS AND HARMONICS – CUSTOMERs operating equipment causing harmonic currents and/or highly fluctuating or large instantaneous demands, including, but not limited to, variable speed drives, motor starting, welders and X-ray machines, shall be required to pay all nonbetterment costs of corrective action required to maintain acceptable service quality to the CUSTOMER and not interfere with service on LES' lines or to other CUSTOMERS. See System Disturbances and Service Disruptions, and Disconnection of Electric Service in the Service Regulations.
6. COGENERATION OR SMALL POWER PRODUCTION – Refer to Customer-Owned Generation in the Service Regulations.

NEBRASKA PUBLIC POWER DISTRICT

Schedule: RS **Issued:** 8/15/18
Supersedes Schedule: RS **Issued:** 12/20/17
Sheet No.: 1 **of** 3 **Sheets**

RESIDENTIAL SERVICE RATE SCHEDULE

(Name of Schedule)

AVAILABLE: In the retail distribution service territory of the District.

APPLICABLE: To single-family residences and individually metered apartments for all domestic purposes when all service is supplied through a single meter.

CHARACTER OF SERVICE: AC, 60 hertz, single-phase or three-phase, at any of the District's standard secondary voltages.

BASE RATE:

Subject to application of Retail Production Cost Adjustment (PCA) Rate Schedule.

Residential Service:

Customer Charge: $22.50 per month

Energy Charge:

Summer	Winter	
10.13¢	8.08¢	per kilowatt-hour for the first 750 kilowatt-hours used per month.
10.13¢	6.22¢	per kilowatt-hour for all additional use.

Summer:

The summer rate shall apply to the Customer's prorated use from June 1 through September 30.

Winter:

The winter rate shall apply to the Customer's prorated use from October 1 through May 31.

TAX CLAUSE: In the event of the imposition of any new or increased tax or any payment in lieu thereof, in excess of that provided for under Article VIII, Section 11 of the Nebraska Constitution, by any lawful authority on the production, transmission, or sale of electricity, the rate provided herein may be increased to reflect the amount of such tax or in lieu of tax increase.

Effective: September 1, 2018

Approved: 8/9/18 **Resolution No:** 18-25 **Issued by:**

NEBRASKA PUBLIC POWER DISTRICT

Schedule: RS **Issued:** 8/15/18

Supersedes Schedule: RS **Issued:** 12/20/17

Sheet No.: 2 **of** 3 **Sheets**

RESIDENTIAL SERVICE RATE SCHEDULE

(Name of Schedule)

BASE RATE ADJUSTMENT:

Customers who are served from distribution facilities for which the District has a Lease Payment (LP) or Debt Service (DS) obligation and/or a 5% Gross Revenue Tax (GRT) obligation will have the Base Rate (excluding PCA) adjusted to include such obligations as shown in the following table :

Applicable Adjustment	Rate Formula
None	Base Rates
Gross Revenue Tax (GRT) Only	Base Rates ÷ 0.95
Lease Payment (LP) or Debt Service (DS) Only	Base Rates ÷ (1 - applicable Lease Payment or Debt Service obligation percentage)
LP/DS and GRT	Base Rates ÷ (1 - (5% + applicable Lease Payment or Debt Service obligation percentage))

In addition, for Customers served from distribution facilities for which the District has a 5% GRT obligation, the PCA will be adjusted to include such obligation by the following formula: PCA ÷ 0.95.

MINIMUM BILL: Customer Charge, subject to applicable Base Rate Adjustment.

TERMS AND CONDITIONS:

1. Service will be furnished under the District's Retail Service Rules and Regulations.
2. Extensions made for service under this Rate Schedule are subject to the provisions of the District's "General Extension Policy for Retail Electric Services and Facilities".
3. The District's General Customer Service Charges Rate Schedule shall apply.

TAX CLAUSE: In the event of the imposition of any new or increased tax or any payment in lieu thereof, in excess of that provided for under Article VIII, Section 11 of the Nebraska Constitution, by any lawful authority on the production, transmission, or sale of electricity, the rate provided herein may be increased to reflect the amount of such tax or in lieu of tax increase.

Effective: September 1, 2018

Approved: 8/9/18 **Resolution No:** 18-25 **Issued by:**

NEBRASKA PUBLIC POWER DISTRICT

Schedule: RS **Issued:** 8/15/18
Supersedes Schedule: RS **Issued:** 12/20/17
Sheet No.: 3 **of** 3 **Sheets**

RESIDENTIAL SERVICE RATE SCHEDULE

(Name of Schedule)

4. Usage shall be prorated for application of a change in rate or changing from summer to winter or from winter to summer rates. Such proration shall be accomplished by utilizing either the Customer's actual usage in each time period, or by fractionalizing the Customer's total usage according to the number of days of service corresponding to each time period by using the District's billing system.

5. At the option of the District, an energy load management switch may be installed that enables the District to turn off the electric water heater for periods of four (4) hours per day when there is an economic need to manage usage.

6. For billing purposes, energy usage shall be normalized to 30 days when actual days of service is less than 27 days or exceeds 35 days in any given billing period.

7. The District retains and reserves the right, power and authority to modify, revise, amend, replace, repeal or cancel this Rate Schedule, at any time and in whole or in part, by resolution adopted by the District's Board of Directors.

TAX CLAUSE: In the event of the imposition of any new or increased tax or any payment in lieu thereof, in excess of that provided for under Article VIII, Section 11 of the Nebraska Constitution, by any lawful authority on the production, transmission, or sale of electricity, the rate provided herein may be increased to reflect the amount of such tax or in lieu of tax increase.

Effective: September 1, 2018
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NEBRASKA PUBLIC POWER DISTRICT

Schedule: GS **Issued:** 8/15/18

Supersedes Schedule: GS **Issued:** 12/20/17

Sheet No.: 1 **of** 3 **Sheets**

GENERAL SERVICE RATE SCHEDULE

(Name of Schedule)

AVAILABLE: In the retail distribution service territory of the District.

APPLICABLE: To commercial and nonresidential establishments for lighting, heating, and power purposes where all service is taken through a single meter at one location, and where the Customer's peak demand does not exceed 100 kW during any two summer months or 200 kW in any two months of a 12 consecutive month period. However, any commercial Customer with a load factor of at least 250 kWh/kW and either: (1) a demand greater than 50 kW, or (2) monthly consumption greater than 15,000 kWh during any three months of a 12 consecutive month period shall have the option of being billed under the General Service Demand Rate Schedule.

CHARACTER OF SERVICE: AC, 60 hertz, single-phase or three-phase, at any of the District's standard primary and secondary distribution voltages.

BASE RATE:

Subject to application of Retail Production Cost Adjustment (PCA) Rate Schedule.

General Service (Rate Codes 27 & 52):

Customer Charge:	Single-phase	$32.50 per month
	Three-phase	$48.50 per month

Energy Charge:

Summer	Winter	
9.73¢	7.33¢	per kilowatt-hour for all use.

Summer:

The summer rate shall apply to the Customer's prorated use from June 1 through September 30.

Winter:

The winter rate shall apply to the Customer's prorated use from October 1 through May 31.

TAX CLAUSE: In the event of the imposition of any new or increased tax or any payment in lieu thereof, in excess of that provided for under Article VIII, Section 11 of the Nebraska Constitution, by any lawful authority on the production, transmission, or sale of electricity, the rate provided herein may be increased to reflect the amount of such tax or in lieu of tax increase.

Effective: September 1, 2018

Approved: 8/9/18 **Resolution No:** 18-25 **Issued by:**

NEBRASKA PUBLIC POWER DISTRICT

Schedule: GS **Issued:** 8/15/18
Supersedes Schedule: GS **Issued:** 12/20/17
Sheet No.: 2 **of** 3 **Sheets**

GENERAL SERVICE RATE SCHEDULE

(Name of Schedule)

BASE RATE ADJUSTMENT:

Customers who are served from distribution facilities for which the District has a Lease Payment (LP) or Debt Service (DS) obligation and/or a 5% Gross Revenue Tax (GRT) obligation will have the Base Rate (excluding PCA but including applicable primary service discount) adjusted to include such obligations as shown in the following table:

Applicable Adjustment	Rate Formula
None	Base Rates
Gross Revenue Tax (GRT) Only	Base Rates ÷ 0.95
Lease Payment (LP) or Debt Service (DS) Only	Base Rates ÷ (1 - applicable Lease Payment or Debt Service obligation percentage)
LP/DS and GRT	Base Rates ÷ (1 - (5% + applicable Lease Payment or Debt Service obligation percentage))

In addition, for Customers served from distribution facilities for which the District has a 5% GRT obligation, the PCA will be adjusted to include such obligation by the following formula: PCA ÷ 0.95.

MINIMUM BILL: Customer Charge, subject to applicable Base Rate Adjustment.

PRIMARY SERVICE DISCOUNT: A discount of two percent (2%) of the total bill (excluding applicable PCA and Base Rate Adjustment) is applicable where:

1. The Customer takes service from the District's standard primary distribution voltage,

2. The Customer owns and maintains, or pays for all capital costs and all costs for repairs, renewals, improvements and additions, for all transformation from primary distribution voltage to Customer secondary utilization voltage and other distribution facilities beyond the primary voltage delivery point, and

TAX CLAUSE: In the event of the imposition of any new or increased tax or any payment in lieu thereof, in excess of that provided for under Article VIII, Section 11 of the Nebraska Constitution, by any lawful authority on the production, transmission, or sale of electricity, the rate provided herein may be increased to reflect the amount of such tax or in lieu of tax increase.

Effective: September 1, 2018

Approved: 8/9/18 **Resolution No:** 18-25 **Issued by:** Todd A. Aust

NEBRASKA PUBLIC POWER DISTRICT

Schedule: GS **Issued:** 8/15/18
Supersedes Schedule: GS **Issued:** 12/20/17
Sheet No.: 3 **of** 3 **Sheets**

GENERAL SERVICE RATE SCHEDULE

(Name of Schedule)

3. Both the point of measurement and the point of delivery are located at the same point on the District's primary voltage distribution line.

TERMS AND CONDITIONS:

1. Service will be furnished under the District's Retail Service Rules and Regulations.
2. Extensions made for service under this Rate Schedule are subject to the provisions of the District's "General Extension Policy for Retail Electric Services and Facilities".
3. The District's General Customer Service Charges Rate Schedule shall apply.
4. Usage shall be prorated for application of a change in rate or changing from summer to winter or from winter to summer rates. Such proration shall be accomplished by utilizing either the Customer's actual usage in each time period, or by fractionalizing the Customer's total usage according to the number of days of service corresponding to each time period by using the District's billing system.
5. For billing purposes, energy usage shall be normalized to 30 days when actual days of service is less than 27 days or exceeds 35 days in any given billing period.
6. The District retains and reserves the right, power and authority to modify, revise, amend, replace, repeal or cancel this Rate Schedule, at any time and in whole or in part, by resolution adopted by the District's Board of Directors.

TAX CLAUSE: **In the event of the imposition of any new or increased tax or any payment in lieu thereof, in excess of that provided for under Article VIII, Section 11 of the Nebraska Constitution, by any lawful authority on the production, transmission, or sale of electricity, the rate provided herein may be increased to reflect the amount of such tax or in lieu of tax increase.**

Effective: September 1, 2018
Approved: 8/9/18 **Resolution No:** 18-25 **Issued by:**

NEBRASKA PUBLIC POWER DISTRICT

Schedule: CESH **Issued:** 8/15/18
Supersedes Schedule: CESH **Issued:** 12/20/17
Sheet No.: 1 **of** 4 **Sheets**

COMMERCIAL ELECTRIC SPACE HEATING RATE SCHEDULE

(Name of Schedule)

AVAILABLE: In the retail distribution service territory of the District.

APPLICABLE: To commercial and industrial Customers when all of the service at one location meets the following requirements:

1. Service is measured by one meter.
2. Electricity is the primary (greater than 50%) source of energy for space heating.
3. The Customer's maximum integrated kilowatt load during any thirty (30) minute period exceeds 25 kilowatts (kW). (This requirement is waived for Customers taking service under this Rate Schedule prior to January 1, 2002).

CHARACTER OF SERVICE: AC, 60 hertz, single-phase or three-phase, at any of the District's standard primary and secondary distribution voltages.

BASE RATE:

Subject to application of Retail Production Cost Adjustment (PCA) Rate Schedule.

Commercial Electric Space Heating (Rate Code 29):

Customer Charge:	Single-phase	$54.00 per month
	Three-phase	$72.50 per month

Energy Charge:

Summer	Winter	
12.74¢	9.16¢	per kilowatt-hour for the first 200 kilowatt-hours per kilowatt of billing demand.
4.77¢	3.72¢	per kilowatt-hour for all additional use.

TAX CLAUSE: In the event of the imposition of any new or increased tax or any payment in lieu thereof, in excess of that provided for under Article VIII, Section 11 of the Nebraska Constitution, by any lawful authority on the production, transmission, or sale of electricity, the rate provided herein may be increased to reflect the amount of such tax or in lieu of tax increase.

Effective: September 1, 2018

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NEBRASKA PUBLIC POWER DISTRICT

Schedule: CESH **Issued:** 8/15/18
Supersedes Schedule: CESH **Issued:** 12/20/17
Sheet No.: 2 **of** 4 **Sheets**

COMMERCIAL ELECTRIC SPACE HEATING RATE SCHEDULE

(Name of Schedule)

Summer:

The summer rate shall apply to the Customer's prorated use from June 1 through September 30.

Winter:

The winter rate shall apply to the Customer's prorated use from October 1 through May 31.

BASE RATE ADJUSTMENT:

Customers who are served from distribution facilities for which the District has a Lease Payment (LP) or Debt Service (DS) obligation and/or a 5% Gross Revenue Tax (GRT) obligation will have the Base Rate (excluding PCA but including applicable primary service discount) adjusted to include such obligations as shown in the following table:

Applicable Adjustment	Rate Formula
None	Base Rates
Gross Revenue Tax (GRT) Only	Base Rates ÷ 0.95
Lease Payment (LP) or Debt Service (DS) Only	Base Rates ÷ (1 - applicable Lease Payment or Debt Service obligation percentage)
LP/DS and GRT	Base Rates ÷ (1 - (5% + applicable Lease Payment or Debt Service obligation percentage))

In addition, for Customers served from distribution facilities for which the District has a 5% GRT obligation, the PCA will be adjusted to include such obligation by the following formula: PCA ÷ 0.95.

MINIMUM BILL: Customer Charge, subject to applicable Base Rate Adjustment.

TAX CLAUSE: In the event of the imposition of any new or increased tax or any payment in lieu thereof, in excess of that provided for under Article VIII, Section 11 of the Nebraska Constitution, by any lawful authority on the production, transmission, or sale of electricity, the rate provided herein may be increased to reflect the amount of such tax or in lieu of tax increase.

Effective: September 1, 2018

Approved: 8/9/18 **Resolution No:** 18-25 **Issued by:**

NEBRASKA PUBLIC POWER DISTRICT

Schedule: CESH **Issued:** 8/15/18
Supersedes Schedule: CESH **Issued:** 12/20/17
Sheet No.: 3 **of** 4 **Sheets**

COMMERCIAL ELECTRIC SPACE HEATING RATE SCHEDULE

(Name of Schedule)

DETERMINATION OF BILLING DEMAND: The billing demand for extension of the kilowatt-hour blocks in the above rate shall be the maximum integrated kilowatt load during any thirty (30) minute period occurring in the billing period for which the determination is made.

PRIMARY SERVICE DISCOUNT: A discount of two percent (2%) of the total bill (excluding applicable PCA and Base Rate Adjustment) is applicable where:

1. The Customer takes service from the District's standard primary distribution voltage,

2. The Customer owns and maintains, or pays for all capital costs and all costs for repairs, renewals, improvements and additions, for all transformation from primary distribution voltage to Customer secondary utilization voltage and other distribution facilities beyond the primary voltage delivery point, and

3. Both the point of measurement and the point of delivery are located at the same point on the District's primary voltage distribution line.

POWER FACTOR ADJUSTMENT: The rates set forth in this Rate Schedule are based on the maintenance by the Customer of a power factor of not less than 90%, whether lagging or leading, at all times. For loads of 750 kW or more, or at the option of the District for loads of less than 750 kW, power factor adjustments will be made in the billing demand. The measured maximum kW demand will be multiplied by 90 percent and divided by the Customer's power factor (expressed in percent) determined at the time of the Customer's maximum use.

TERMS AND CONDITIONS:

1. Service will be furnished under the District's Retail Service Rules and Regulations.

2. Extensions made for service under this Rate Schedule are subject to the provisions of the District's "General Extension Policy for Retail Electric Services and Facilities".

3. The District's General Customer Service Charges Rate Schedule shall apply.

TAX CLAUSE: In the event of the imposition of any new or increased tax or any payment in lieu thereof, in excess of that provided for under Article VIII, Section 11 of the Nebraska Constitution, by any lawful authority on the production, transmission, or sale of electricity, the rate provided herein may be increased to reflect the amount of such tax or in lieu of tax increase.

Effective: September 1, 2018
Approved: 8/9/18 **Resolution No:** 18-25 **Issued by:**

NEBRASKA PUBLIC POWER DISTRICT

Schedule: CESH **Issued:** 8/15/18
Supersedes Schedule: CESH **Issued:** 12/20/17
Sheet No.: 4 **of** 4 **Sheets**

COMMERCIAL ELECTRIC SPACE HEATING RATE SCHEDULE

(Name of Schedule)

4. Usage shall be prorated for application of a change in rate or changing from summer to winter or from winter to summer rates. Such proration shall be accomplished by utilizing either the Customer's actual usage in each time period, or by fractionalizing the Customer's total usage according to the number of days of service corresponding to each time period by using the District's billing system.

5. For billing purposes, energy usage shall be normalized to 30 days when actual days of service is less than 27 days or exceeds 35 days in any given billing period.

6. The District retains and reserves the right, power and authority to modify, revise, amend, replace, repeal or cancel this Rate Schedule, at any time and in whole or in part, by resolution adopted by the District's Board of Directors.

TAX CLAUSE: In the event of the imposition of any new or increased tax or any payment in lieu thereof, in excess of that provided for under Article VIII, Section 11 of the Nebraska Constitution, by any lawful authority on the production, transmission, or sale of electricity, the rate provided herein may be increased to reflect the amount of such tax or in lieu of tax increase.

Effective: September 1, 2018
Approved: 8/9/18 **Resolution No:** 18-25 **Issued by:**

Omaha Public Power District
Energy Plaza - Omaha, NE

Electric Rate Schedule
Effective January 1, 2019
Resolution No. 6093

SCHEDULE NO. 110

RESIDENTIAL SERVICE

Availability:

To single-family dwellings, farms including only one residential dwelling, trailers, or to each of the units of flats, apartment houses, or multi-family dwellings, when such units are metered individually in the District's Service Area. A "unit" shall be a trailer, apartment, flat, or unit of a multi-family dwelling, equipped with cooking facilities.

The single phase, alternating current, electric service will be supplied at the District's standard voltages of 240 volts or less, for residential uses, when all electric service furnished under this Schedule is measured by one meter. This Rate Schedule includes service for air-conditioning motors not exceeding 7 1/2 horsepower each, other motors not exceeding 3 horsepower each; but excludes X-ray and other appliances producing abnormal voltage fluctuations. Not applicable to shared or resale service.

Monthly Rate:

A Service Charge of: $30.00 plus

An Energy Charge of:
Summer 9.36 cents per kilowatthour for all kilowatthours.

For kilowatthour consumption of more than 100 kilowatthours and less than 401 kilowatthours, a credit of $2.07 per month will be applied.

The summer rate will be applicable June 1 through September 30.

Winter 8.63 cents per kilowatthour for the first 100 kilowatthours,
7.46 cents per kilowatthour for the next 900 kilowatthours,
5.27 cents per kilowatthour for all over 1000 kilowatthours.

The winter rate will be applicable October 1 through May 31.

The provisions of Rate Schedule No. 461 – Fuel and Purchased Power Adjustment apply to this rate schedule.

Minimum Monthly Bill: $32.07

Late Payment Charge:

A Late Payment Charge in the amount of 4% of the Monthly Rate and applicable taxes will be assessed if the current month’s bill payment is not received by the District on or before the due date.

For customers on the District’s Level Payment Plan, the Late Payment Charge will be calculated as 4% of the current month’s level payment amount.

SCHEDULE NO. 110

RESIDENTIAL SERVICE

Reconnection Charge:

If a Consumer whose service has been terminated has such service reconnected within 12 months of such termination, a reconnection charge equal to the minimum monthly charge for the preceding 12 months, or any part thereof, shall be collected by the District.

Service Regulations:

The District's Service Regulations form a part of this schedule.

District Level Payment Plan:

Upon mutual agreement, the Consumer may elect to be billed on the District's Level Payment Plan.

Large Farm and Residential Service:

Large Farm and Residential Service may be provided under this Schedule for larger motors, welders, crop dryers, snow melting equipment, elevators, hoists, or similar equipment; where the District's distribution facilities are suitable for the service required. Transformers larger than 25 kVA capacity may be installed at the District's option.

Special Conditions:

If a building served through one meter can be a residence for two, three or four families, each family unit having separate cooking facilities, this schedule, except the summer credit, may be applied through mutual agreement between the Consumer and the District, by multiplying the number of kilowatthours in each block, except the Service Charge of the Monthly Rate, by the number of dwelling units in the buildings; otherwise, the General Service Schedule will apply.

The Consumer's water heating and space heating equipment shall be a type approved by the District and shall be installed in accordance with the District's Service Regulations.

SCHEDULE NO. 115

RESIDENTIAL CONSERVATION SERVICE

Availability:

To single-family dwellings, farms including only one residential dwelling, trailers, or to each of the units of flats, apartment houses, or multi-family dwellings, when such units are metered individually in the District's Service Area. A "unit" shall be a trailer, apartment, flat, or unit of a multi-family dwelling, equipped with cooking facilities.

The single phase, alternating current, electric service will be supplied at the District's standard voltages of 240 volts or less, for residential uses, when all electric service furnished under this Schedule is measured by one meter. This Rate Schedule includes service for air-conditioning motors not exceeding 7 1/2 horsepower each, other motors not exceeding 3 horsepower each; but excludes X-ray and other appliances producing abnormal voltage fluctuations. Not applicable to shared or resale service.

Qualification Requirements:

To qualify for this rate schedule, the Consumer must (1) apply for service under this rate schedule, (2) have an electric heat pump in operation that has a Seasonal Energy Efficiency Rating of 14 or higher with the heat pump installation passing the District's size and efficiency tests, and (3) supply at least 50% of the space conditioning requirements using the electric heat pump.

New or existing Rate Schedule No. 115 Consumers living in a premise with an electric heat pump that was installed and qualified for the rate prior to January 1, 2016 may be served on Rate Schedule No. 115 at the premise for the Schedule Duration.

Monthly Rate:

A Service Charge of: $30.00 plus

An Energy Charge of:
Summer 9.36 cents per kilowatthour for all kilowatthours.

For kilowatthour consumption of more than 100 kilowatthours and less than 401 kilowatthours, a credit of $2.07 per month will be applied.

The summer rate will be applicable June 1 through September 30.

Winter 8.63 cents per kilowatthour for the first 100 kilowatthours,
7.46 cents per kilowatthour for the next 780 kilowatthours.
4.31 cents per kilowatthour for all over 880 kilowatthours.

The winter rate will be applicable October 1 through May 31.

The provisions of Rate Schedule No. 461 – Fuel and Purchased Power Adjustment apply to this rate schedule.

SCHEDULE NO. 115

RESIDENTIAL CONSERVATION SERVICE

Minimum Monthly Bill: $32.07

Late Payment Charge:

A Late Payment Charge in the amount of 4% of the Monthly Rate and applicable taxes will be assessed if the current month's bill payment is not received by the District on or before the due date.

For customers on the District's Level Payment Plan, the Late Payment Charge will be calculated as 4% of the current month's level payment amount.

Schedule Duration:

Five years or longer for customers that meet the Qualification Requirements of this rate schedule. Availability beyond five years will continue until the termination of the heat pump program and the last customer to qualify for this rate schedule completes the minimum five year availability.

Reconnection Charge:

If a Consumer whose service has been terminated has such service reconnected within 12 months of such termination, a reconnection charge equal to the minimum monthly charge for the preceding 12 months, or any part thereof, shall be collected by the District.

Service Regulations:

The District's Service Regulations form a part of this schedule.

District Level Payment Plan:

Upon mutual agreement, the Consumer may elect to be billed on the District's Level Payment Plan.

Large Farm and Residential Service:

Large Farm and Residential Service may be provided under this Schedule for larger motors, welders, crop dryers, snow melting equipment, elevators, hoists, or similar equipment; where the District's distribution facilities are suitable for the service required. Transformers larger than 25 kVA capacity may be installed at the District's option.

Special Conditions:

If a building served through one meter can be a residence for two, three or four families, each family unit having separate cooking facilities, this schedule, except the summer credit, may be applied through mutual agreement between the Consumer and the District, by multiplying the number of kilowatthours in each block, except the Service Charge of the Monthly Rate, by the number of dwelling units in the buildings; otherwise, the General Service Schedule will apply.

The Consumer's water heating and space heating equipment shall be a type approved by the District and shall be installed in accordance with the District's Service Regulations.

Omaha Public Power District
Energy Plaza - Omaha, NE

Electric Rate Schedule
Effective January 1, 2019
Resolution No. 6093

SCHEDULE NO. 230

GENERAL SERVICE – NON-DEMAND

Availability:

To all Consumers throughout the District's Service Area that have Monthly Billing Demands less than 50 kW during each of the four Summer billing months.

The single phase, or three phase if available, alternating current, electric service will be supplied at the District's standard voltages, for all uses, when all the Consumer's service at one location is measured by one kilowatthour meter with or without a demand register, unless a Consumer takes emergency or special service as required by the District's Service Regulations. Not applicable to shared or resale service.

This rate is not available to those Consumers taking Irrigation Service as identified in Rate Schedule No. 226.

Monthly Rate:

A Service Charge of: $33.00 plus

An Energy Charge of:

Summer	9.11 cents per kilowatthour for the first 1,000 kilowatthours, 8.40 cents per kilowatthour for all over 1,000 kilowatthours.
	The summer rate will be applicable June 1 through September 30
Winter	7.89 cents per kilowatthour for the first 3,000 kilowatthours, 5.24 cents per kilowatthour for all over 3,000 kilowatthours.
	The winter rate will be applicable October 1 through May 31.

The provisions of Rate Schedule No. 461 – Fuel and Purchased Power Adjustment apply to this rate schedule.

Minimum Monthly Bill: $33.00

Late Payment Charge:

A Late Payment Charge in the amount of 4% of the Monthly Rate and applicable taxes will be assessed if the current month's bill payment is not received by the District on or before the due date.

For customers on the District's Level Payment Plan, the Late Payment Charge will be calculated as 4% of the current month's level payment amount.

Schedule Duration:

One year, or longer, at the District's option.

SCHEDULE NO. 230

GENERAL SERVICE – NON-DEMAND

Reconnection Charge:

If a Consumer whose service has been terminated has such service reconnected within 12 months of such termination, a reconnection charge equal to the minimum monthly charge for the preceding 12 months, or any part thereof, shall be collected by the District.

Determination of Demand:

Demand, for any billing period, shall be the kilowatts as shown by or computed from the readings of the District's kilowatthour meter with a demand register or the District's check meter, for the 15-minute period of Consumer's greatest use during such billing period.

If the demand, so determined, however, is less than 85% of the Consumer's highest 15-minute kilovoltampere demand, the kilowatt demand will be increased for the purposes of this schedule by 50% of the difference between 85% of the kilovoltampere demand and the demand as determined above.

Such demand must be equal to or greater than the larger of the following:

> 85% of the highest 15-minute power factor adjusted demand during the summer billing months of the preceding 11 months, or
>
> 60% of the highest 15-minute power factor adjusted demand during the winter billing months of the preceding 11 months.

Service Regulations:

The District's Service Regulations form a part of this schedule.

District Level Payment Plan:

For Consumers meeting the eligibility requirements specified in the District's Service Regulations, the Consumer may elect to be billed on the District's Level Payment Plan.

Special Conditions:

Consumer shall furnish, if requested, suitable space on the Consumer's premises for the District's transforming equipment, and if required, suitable space for switching and/or capacitor equipment.

The Consumer's water heating and space heating equipment shall be a type approved by the District and shall be installed in accordance with the District's Service Regulations.

District shall not be required to furnish duplicate service hereunder.

NEBRASKA PUBLIC SERVICE COMMISSION
NATURAL GAS RATE SCHEDULE
for
NORTHWESTERN CORPORATION d/b/a NORTHWESTERN ENERGY

Section No. 3
1st Revised Sheet No. 1
Canceling Original Sheet No. 1

CLASS OF SERVICE: **Residential Gas Service** **Rate No. 91**
RATE DESIGNATION: **Firm Sales**

1. Applicability

This rate is available to domestic customers whose maximum requirements for natural gas are not more than 200 therms per day. The nameplate input ratings of all gas burning equipment shall be used to determine a customer's maximum requirements, based on 10 hours use per day.

2. Territory

The area served with natural gas by the Company in Nebraska.

3. Rates

Monthly Charges:

Customer Charge per Meter:	$ 8.00
Non-Gas Commodity Charge:	
First 30 therms, per therm	$ 0.25283
Over 30 therms, per therm	$ 0.09513
Standby Capacity Charge - *December through March*:	$ 12.00
City Approved Economic Development Surcharge	$ 0.00254
Minimum Monthly Bill:	$ 8.00

Adjustment Clauses:

a. Purchased Gas Cost Adjustment Clause shall apply. (Sheet Nos. 7, 7.1)
b. BTU Adjustment Clause shall apply. (Sheet Nos. 8, 8.1)

4. Other Provisions

The Standby Charge is applicable to customers using service pursuant to this schedule as a backup fuel source to an alternately fueled heating system. This charge is not applicable where natural gas service is the primary heating fuel source.

Service will be furnished under the Company's General Terms and Conditions.

Date Filed: June 1, 2007 **Effective Date: December 1, 2007**
Issued By: Jeffrey Decker, Regulatory Department
Phone (605) 353-8315

NEBRASKA PUBLIC SERVICE COMMISSION
NATURAL GAS RATE SCHEDULE
for
NORTHWESTERN CORPORATION d/b/a NORTHWESTERN ENERGY

Section No. 3
1st Revised Sheet No. 2
Canceling Original Sheet No. 2

CLASS OF SERVICE: **General Gas Service** **Rate No. 92**
RATE DESIGNATION: **Firm Sales**

1. Applicability

This rate is available to non-residential customers whose maximum requirements for natural gas are not more than 200 therms per day. If no historical peak day usage is available, the nameplate input ratings of all gas burning equipment shall be used to determine a customer's maximum requirements.

2. Territory

The area served with natural gas by the Company in Nebraska.

3. Rates

Monthly Charges:

Customer Charge per Meter:	$ 9.00
Non-Gas Commodity Charge:	
First 400 therms, per therm	$ 0.13332
Next 1,600 therms, per therm	$ 0.06343
Over 2,000 therms, per therm	$ 0.03743
Standby Capacity Charge - *December through March*:	$ 37.00
City Approved Economic Development Surcharge	$ 0.00254
Minimum Monthly Bill:	$ 9.00

Adjustment Clauses:

a. Purchased Gas Cost Adjustment Clause shall apply. (Sheet Nos. 7, 7.1)
b. BTU Adjustment Clause shall apply. (Sheet Nos. 8, 8.1)

4. Other Provisions

The Standby Charge is applicable to customers using service pursuant to this schedule as a backup fuel source to an alternately fueled heating system. This charge is not applicable where natural gas service is the primary heating fuel source.

Service will be furnished under the Company's General Terms and Conditions.

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Black Hills Nebraska Gas, LLC **Exhibit TJS-7**

FULLY COST BASED AND PROPOSED RATES

FOR THE PRO FORMA PERIOD ENDED DECEMBER 31, 2020

	A	B	C	D
Line No.	**Description**		**Residential**	**Commercial**
1	1. Customer Related Costs - $/bill			
2	Distribution - Customer		7.49	14.97
3	Services		7.24	14.48
4	Meters & Regulators		4.92	17.21
5	Customer Accounting		5.33	8.00
6	Jurisdiction Direct		-0.55	-0.99
7	Total		24.42	53.67
8				
9	2. Cost of Service			
10	Customer Charge	$/Month	$24.50	$54.00
11				
12	Therm Threshold		**20 Therms**	**40 Therms**
13	Distribution Charge Tier 1	$/Therm	0.12090	0.11810
14				
15	Therm Threshold		**>20 Therms**	**> 40 Therms**
16	Distribution Charge Tier 2	$/Therm	0.12090	0.11810
17				
18	3. Proposed Rates			
19	Customer Charge	$/Month	$15.45	$31.10
20				
21	Therm Threshold		**20 Therms**	**40 Therms**
22	Distribution Charge Tier 1	$/Therm	0.59960	0.59960
23				
24	Therm Threshold		**>20 Therms**	**> 40 Therms**
25	Distribution Charge Tier 2	$/Therm	0.15000	0.15000
26				
27	4. Alternate Rates			
28	Customer Charge	$/Month	$22.81	$43.65
29	Volumetric Charge	$/Therm	0.1500	0.1500