SUBJECT: **SaskPower's Response to the *Review of SaskPower's Cost Allocation and Rate Design Methodologies* final report of June 30, 2017, Prepared by Elenchus Research Associates Inc.**

DATE: **September 19, 2017**

Purpose

The purpose of this communication is to summarize the recommendations in the final report prepared by Elenchus Research Associates of its 2017 review of SaskPower's cost of service and rate design methodologies, indicate which of the recommendations will be implemented, and communicate the approximate impact of those changes.

The project scope, Elenchus' recommendations and SaskPower's responses are summarized in Appendix A.

Background

SaskPower's current cost of service model was developed in 1985 and previously reviewed in 1998, 2002, 2008 and 2012. The model was updated in 1998, 2002, 2009 and 2014 based on the recommendations made from those reviews.

At the present time, the Saskatchewan government oversees utility cost of service and rate changes with the aid of the Saskatchewan Rate Review Panel (SRRP). The SRRP has mandated that SaskPower's cost of service methodology be reviewed every 5 years by an independent technical consultant, with input from interested stakeholders, to verify whether the current methodology is consistent with accepted electric power utility practices and is appropriate for SaskPower's system characteristics. The SRRP was an active stakeholder in this review, but will not submit a final report at the review's conclusion.

During the Request for Proposals stage, stakeholders were encouraged to offer feedback on the proposed scope of the review, as well as provide input into the evaluation process used to select the independent technical consultant. In January 2017, SaskPower engaged the services of Elenchus Research Associates, from Toronto, Ontario, to review its cost of service methodology. Elenchus promptly began reviewing SaskPower's methodologies and models and presented its preliminary findings and draft recommendations during two public meetings held in Regina on March 30 and May 15, 2017.

At each meeting, Elenchus presented its findings to date, outlined its opinions, made recommendations for enhancements, and showed the potential impacts of its recommendations on customers, where applicable. At both events, Elenchus responded to inquiries and/or concerns from interested stakeholders and invited them to submit written questions and submissions. These are included, along with Elenchus' responses, in the final report. Elenchus' services were made available to respond to any interrogatories from interested stakeholders at any time during the review process, either directly through their SaskPower account representative or via the 2017 Cost of Service Methodology Review webpage located on SaskPower's corporate website.

Various representatives from the SRRP, the cities of Saskatoon and Swift Current, the Canadian Association of Petroleum Producers (CAPP), the Saskatchewan Industrial Energy Consumers Association (SIECA), and members of the general public were in attendance or listening via conference call to the proceedings. All correspondence, including the audio recordings of the events, has been posted to SaskPower's website.

Elenchus' Recommendations

Elenchus filed its final report on June 30, 2017. It states the view that SaskPower's current cost allocation methodology is consistent with accepted rate-making principles and practices, as well as the methodologies commonly used by other electric utilities, and is consistent with, and reflective of, SaskPower's operational circumstances, with some recommendations for enhancements:

1) Implement the "**Average and Excess**" method to classify SaskPower's generating assets between energy and demand.

2) Implement the "**Minimum System**" method to classify distribution transformers and urban and rural distribution line costs between demand and customer.

3) Replace the existing Non-Coincident Peak (NCP) data used for allocation purposes with the **Class Maximum Diversified Demand (MDD)**.

SaskPower's Response

SaskPower has reviewed Elenchus' recommendations and has made the following comments:

1) Implement the "Average and Excess" method to classify SaskPower's generating assets between energy and demand.

SaskPower currently uses the **Equivalent Peaker Method (EPM)** to classify its generation assets between energy and demand. The premises of this methodology are that (1) increases in peak demand require the addition of peaking capacity only; and (2) that utilities incur the costs of more expensive baseload units because of the additional energy loads they must serve (NARUC, 1992, pg.53). Therefore, peaking plants, such as a Simple Cycle Gas Turbine (SCGT) are classified 100% to demand under the EPM. The difference between the total cost for a new generation plant and the cost of a peaking plant is caused by the energy loads to be served and is therefore classified as energy related in COS.

There are several emerging issues with this methodology:

i. Standard costing data for conventional coal plants is no longer available, therefore historical, inflation-adjusted data must be used.

ii. Required coal retrofitting regulations required significant capital investments, impacting the results.
iii. Generation assets are no longer typically dispatched for their original purpose (e.g., gas units are no longer dispatched exclusively for peaking).

Elenchus believes that the resulting changes in the calculated demand-energy split under the EPM due to the above factors does not result in a reasonable reflection of cost drivers for SaskPower's generation assets and expenses.

The **Average and Excess Demand (AED) Method** classifies generation assets and expenses using factors that combine each class's average demands over the period with its non-coincident peak demands. The average component in this methodology is based on the ratio of each class's average demand to its peak demand. The excess demand is the difference between the class non-coincident peak and the average demand.

The methodology essentially mirrors a utility's system load factor --- a measure of the energy consumed compared to the energy that would have been consumed at its maximum rate established during the designated time period. A high load factor means power usage is relatively constant; a low load factor means that power usage is relatively inconsistent; with occasional high demands being set.

The rationale behind AED is that a utility's average annual demand is required to meet its energy requirements, and any demand in excess of that average is required to meet its peaking requirements. This is illustrated below:

SaskPower's 2015 Average Demand	= Total Energy Requirements / Annual # of hours = 23,775,308 MWH / 8760 Hours = 2,714 MW
SaskPower's 2015 Maximum Demand	= 3,465 MW
SaskPower's Average to Max Demand ratio	= 2,714 MW / 3,465 MW = **78.3%**

Based on 2015 actuals, using the AED methodology, 78.3% of SaskPower's generating assets and associated expenses would be classified to energy, and 21.7% to demand. This is a substantial shift from the current energy to demand split currently being used within SaskPower's COS under the EPM, as detailed in the table below:

Methodology	Energy (%)	Demand (%)	Total (%)
EPM	54.3%	45.7%	100.0%
AED	78.3%	21.7%	100.0%
Change (%)	**24.0%**	**(24.0%)**	**0.0%**

The customer class impacts of changing from the EPM to AED are detailed in the tables below (based on 2015 actuals):

Customer Class (2015Base)	Original - EPM		AED		Variance	
	Rev Req ($M)	R/RR	Rev Req ($M)	R/RR	Rev Req ($M)	R/RR
Residential	509.2	0.96	502.1	0.98	(7.1)	0.02
Farms	164.9	0.96	163.6	0.97	(1.3)	0.01
Commercial	420.9	1.03	420.4	1.03	(0.5)	0.00
Power	593.9	1.03	600.7	1.01	6.9	(0.02)
Oilfields	324.6	1.02	327.5	1.02	2.9	0.00
Streetlights	17.5	0.86	17.5	0.85	0.1	(0.01)
Reseller	96.8	0.93	95.8	0.94	(1.0)	0.01
Total	**2,127.7**	**1.00**	**2,127.7**	**1.00**	**0.0**	**1.00**

Note – Some columns may not sum to indicated totals due to rounding

A higher R/RR ratio indicates that those customer classes' revenue requirements have decreased under the proposed AED methodology, indicating that these customers would likely experience lower increases than they would have received under the EPM. Conversely, those customer classes with lower R/RR ratios would likely experience higher increases than they would have received under the existing EPM, as their revenue requirements have increased under the proposed AED methodology.

Conclusion:
SaskPower agrees with Elenchus' opinion that the current use of the Equivalent Peaker Method (EPM) is not providing a reasonable, consistent or accurate reflection of SaskPower's cost drivers as they relate to its generation assets and expenses and endorses the use the Average and Excess Demand (AED) Method. To illustrate, the table below shows the impact of the capitalization of the Boundary Dam Carbon Capture and Storage plant in 2014 on the demand/ energy classification ratios produced under the EPM:

	2013	2014	Variance
Demand Related	52.2%	42.5%	9.8%
Energy Related	47.8%	57.5%	9.8%
Total	**100.0%**	**100.0%**	**0.0%**

The addition of one generation asset in 2014 resulted in a nearly 10% change in the Demand/ Energy ratio. If SaskPower continues to use the EPM to calculate the Demand/Energy ratio, the same volatility can be expected every time a major generation asset is capitalized.

SaskPower believes the AED methodology is a superior alternative to the EPM method for the following reasons:

a) It reduces volatility in the demand to energy classification ratio due to additional capitalized generation assets by:
   i. Eliminating estimated cost factors that may no longer be relevant (or accurate) that can vastly affect the outcome; and,
   ii. Disregarding the type of generation technology utilized.
b) It accurately reflects the actual operational circumstances of the utility on a system-wide basis.
c) The impacts to stakeholders are reasonable and manageable.
d) It is relatively simple to understand and easily verified by stakeholders.

SaskPower will implement the AED methodology during the next scheduled rate application by utilizing a 3-year average of SaskPower's system load factor to classify generation assets and expenses. This results in the average value below:

	2013	2014	2015	Average
System Load Factor (2CP)	71.8%	74.2%	78.3%	74.8%

Based on these results, SaskPower will use an energy to demand classification ratio for generation costs of 75% energy and 25% demand during the next scheduled rate application.

2) <u>Implement the "Minimum System" method to classify distribution transformers and urban and rural distribution line costs between demand and customer.</u>

Distribution assets connect transmission assets to customers. Assets that are close to the transmission system tend to be classified in a manner similar to the transmission assets (i.e., demand). Distribution assets that are closer to the customer connections tend to be classified in a manner that is more reflective of other customer-related costs. For example, meter assets and costs are classified as 100% customer related, since they must be incurred regardless of how much power the customer consumes. SaskPower currently uses industry **survey data** to classify its distribution transformers and urban and rural distribution line costs between customer and demand.

The **Minimum System Method (MSM)** calculates the proportion of distribution asset costs that are customer related by taking the ratio of the costs of the smallest distribution assets being used by the utility (e.g., shortest poles) to the costs of all similar assets (e.g., all poles). This process is used to determine the customer components for transformers and line conductors. A common critique of this method is that the customer related portion of the distribution system is able to carry some electricity, therefore some demand related costs would be included in the customer component. To address this concern, an adjustment is made to take into consideration the demand that can be supplied through the minimum system. The adjustment is called the **Peak Load Carrying Capacity (PLCC)**.

The PLCC adjustment determines the theoretical capacity of the minimum system, that is, the capacity of the smallest distribution asset. The capacity of the smallest distribution asset is divided by the number of customers served by the distribution system and an average minimum system capacity per customer is calculated. This average minimum capacity is multiplied by the number of customers in each rate class and the corresponding amount is deducted from the peak demand for that rate class to derive the adjusted peak demand. The adjusted peak demand is used to allocate demand related distribution assets and costs.

At the conclusion of the 2012 Cost of Service Review it was recommended that SaskPower study the potential to implement the MSM for classifying its distribution transformers and lines. SaskPower did examine this option, but was reluctant to implement the methodology until the results could be verified by an external third party. Elenchus Research Associates reviewed and verified SaskPower's calculations of the MSM, the results of which are shown in the table below:

Methodology	Transformers		Lines	
	Customer	Demand	Customer	Demand
Survey Data	30.0%	70.0%	35.0%	65.0%
MSM	35.5%	64.5%	68.5%	31.5%
Change	**5.5%**	**(5.5%)**	**33.5%**	**(33.5%)**

The results show that the customer related portion of distribution lines under the MSM is significantly higher than what SaskPower is currently using. This is not uncommon for low-density utilities such as SaskPower, which serves approximately 3 customers per kilometer of line.

As a result, customer related portions are expected to be higher, as assets are being utilized by fewer customers and the distribution assets are required regardless of how much electricity customers consume.

The customer class impacts of changing from survey data to the MSM are detailed in the tables below (based on 2015 actuals):

Customer Class (2015Base)	Original – Surveys		Minimum System Method		Variance	
	Rev Req ($M)	R/RR	Rev Req ($M)	R/RR	Rev Req ($M)	R/RR
Residential	509.2	0.96	519.0	0.94	9.9	(0.02)
Farms	164.9	0.96	166.4	0.96	1.5	0.00
Commercial	420.9	1.03	415.5	1.04	(5.4)	0.01
Power	593.9	1.03	593.9	1.03	0.0	0.00
Oilfields	324.6	1.02	317.0	1.05	(7.5)	0.03
Streetlights	17.5	0.86	19.0	0.79	1.5	(0.07)
Reseller	96.8	0.93	96.8	0.93	0.0	0.00
Total	**2,127.7**	**1.00**	**2127.7**	**1.00**	**0.0**	**1.00**

Note – Some columns may not sum to indicated totals due to rounding

A higher R/RR ratio indicates that those customer classes' revenue requirements have decreased under the proposed MSM methodology, indicating that these customers would likely experience lower increases than they would have received under the existing methodology. Conversely, those customer classes with lower R/RR ratios would likely experience higher increases than they would have received under the existing methodology, as their revenue requirements have increased under the proposed MSM methodology.

Conclusion:
SaskPower is in agreement with Elenchus' recommendation and endorses the use of the MSM to classify distribution transformers and lateral lines. SaskPower believes the results of its MSM study more accurately reflects SaskPower's circumstances as it pertains to its distribution system and will implement the results during the next scheduled rate application.

For consistency, SaskPower will hold the MSM classification factors to the following levels and examine them again during the next Cost of Service review, scheduled for 2022.

Methodology	Transformers		Lines	
	Customer	Demand	Customer	Demand
MSM	35.0%	65.0%	70.0%	30.0%

3) **<u>Replace the existing Non-Coincident Peak (NCP) data used for allocation purposes with the Class Maximum Diversified Demand (MDD).</u>**

SaskPower currently uses **Non-Coincident Peak (NCP)** demands to allocate the demand related portion of classified costs for distribution transformers within its cost of service. All other demand related costs are allocated based on **Coincident Peak** demand. SaskPower defines these terms as follows:

i. **Coincident Peak Demand (CP)**
This is the demand of a customer or rate class at the time of a specified system peak hour(s). SaskPower's load research includes the coincident peak demands for winter, summer and an average of the two (2CP).

ii. **Non-Coincident Peak Demand (NCP)**
For an individual customer, this is the maximum demand during a specified period for that customer. For the rate class, it is the aggregate of each individual customer's maximum demand regardless of when it occurs.

SaskPower currently aggregates each customer's individual maximum demand, regardless of when it occurs, within a class to calculate their non-coincident peak load factors. Elenchus reviewed the calculations of SaskPower's NCP load factors and their use in the cost allocation study and determined that the **Class Maximum Diversified Demand (MDD)** should be used, as the load factors should be based on the maximum demand of the rate class, as defined below:

iii. **Class Non-Coincident Peak Demand (Class NCP)**
This is the maximum demand of a rate class, regardless of when it occurs, during a specified period. Also known as the **Class Maximum Diversified Demand (MDD)**, it represents the totalized demand of all customers residing within a particular class at the time of the class peak, not the aggregate of their individual maximum demands.

A comparison of SaskPower's NCP values currently used in its cost allocation study and the recommended MDD values are shown in the table below:

Customer Class	NCP			MDD		
	Load Factor %	MW	% of Total	Load Factor %	MW	% of Total
Residential	11.86%	3,009.7	40%	48.89%	730.4	20%
Farms	18.67%	780.2	10%	54.50%	267.3	7%
Commercial	33.45%	1,274.5	17%	63.25%	674.1	19%
Power	63.69%	1,689.0	22%	83.01%	1,295.9	36%
Oilfield	55.99%	564.5	7%	81.57%	387.5	11%
Streetlights	47.12%	14.6	0%	47.12%	14.6	0%
Resellers	58.79%	239.6	3%	58.79%	239.6	7%

Under SaskPower's current definition and usage of NCP, the demand values are excessive and do not reflect Elenchus' experience in other jurisdictions of how NCP load factors are calculated for customer classes. The existing methodology gives too much weighting to the Residential and Farm classes, as these are traditionally low load factor customers whose individual maximum demands, when aggregated, inadvertently allocate more costs to their class (see above table).

The customer class impacts of changing from NCP to MDD are detailed in the tables below (based on 2015 actuals):

Customer Class (2015Base)	Original – NCP		MDD		Variance	
	Rev Req ($M)	R/RR	Rev Req ($M)	R/RR	Rev Req ($M)	R/RR
Residential	509.2	0.96	502.6	0.97	(6.6)	0.01
Farms	164.9	0.96	164.4	0.97	(0.4)	0.01
Commercial	420.9	1.03	424.4	1.02	3.5	(0.01)
Power	593.9	1.03	593.9	1.03	0.0	0.00
Oilfields	324.6	1.02	327.9	1.01	3.4	(0.01)
Streetlights	17.5	0.86	17.7	0.85	0.2	(0.01)
Reseller	96.8	0.93	96.8	0.93	0.0	0.00
Total	**2,127.7**	**1.00**	**2127.7**	**1.00**	**0.0**	**1.00**

The Power and Reseller classes are unaffected by this change, as the MDD is used only to allocate distribution transformers costs which, as transmission customers, neither class would incur at a material level. Therefore, even though their adjusted weightings increase under the MDD, there is no corresponding shift in their revenue requirement.

A higher R/RR ratio indicates that those customer classes' revenue requirements have decreased under the proposed MDD methodology, indicating that these customers would likely experience lower increases than they would have received under the existing methodology. Conversely, those customer classes with lower R/RR ratios would likely experience higher increases than they would have received under the existing methodology, as their revenue requirements have increased under the proposed MDD methodology.

Conclusion:
SaskPower agrees with Elenchus' recommendation and endorses the use of the MDD (Class NCP) methodology to allocate the demand classified portion of distribution transformer costs. SaskPower will implement this change during the next scheduled rate application.

Summary of Impacts

It is important to note that the COS methodology is a zero-sum process, resulting in winners and losers whenever the allocation principles change. The cumulative effect of Elenchus' final recommendations appears in the table below (based on 2015 Actuals):

Customer Class	Revenue Requirement (Existing) ($M)	R/RR Ratio (Existing)	Revenue Requirement (Revised) ($M)	R/RR Ratio (Revised)	Revenue Requirement Change ($M)	R/RR Ratio Change
Residential	509.2	0.96	505.4	0.97	(3.8)	0.01
Farm	164.9	0.96	164.7	0.97	(0.2)	0.01
Commercial	420.9	1.03	418.6	1.03	(2.3)	0.00
Power	593.9	1.03	600.7	1.01	6.9	(0.02)
Oilfields	324.6	1.02	323.3	1.03	(1.2)	0.01
Streetlights	17.5	0.86	19.2	0.78	1.7	(0.08)
Reseller	96.8	0.93	95.8	0.94	(1.0)	0.01
Total	**2127.7**	**1.00**	**2127.7**	**1.00**	**0.0**	**0.00**

The implication of the higher R/RR ratios for the Residential, Farm, Oilfield and Reseller classes is that they will likely experience lower increases than they would have under the original methodology. The implication of the lower R/RR ratio for the Power and Streetlight classes is that they will likely experience higher increases than they would have under the original methodology.

A breakdown of each methodology's impact to the revenue requirement by customer class is summarized in the table below:

Customer Class (2015Base)	Original	AED	MDD	MSM	Revised	Total Variance
	Rev Req ($M)	Rev. Impact	Rev. Impact	Rev. Impact	Rev Req ($M)	Rev Req ($M)
Residential	509.2	(7.1)	(6.6)	9.9	505.4	(3.8)
Farms	164.9	(1.3)	(0.4)	1.5	164.7	(0.2)
Commercial	420.9	(0.5)	3.5	(5.4)	418.6	(2.3)
Power	593.9	6.9	0.0	0.0	600.7	6.9
Oilfields	324.6	2.9	3.4	(7.5)	323.3	(1.2)
Streetlights	17.5	0.1	0.2	1.5	19.2	1.7
Reseller	96.8	(1.0)	0.0	0.0	95.8	(1.0)
Total	**2,127.7**	**0.0**	**0.0**	**0.0**	**2,127.7**	**0.0**

A breakdown of each methodology’s impact to the Revenue to Revenue Requirement ratios (R/RR) by customer class is summarized in the table below:

Customer Class (2015Base)	Original	AED	MDD	MSM	Total Revised
	R/RR	R/RR	R/RR	R/RR	R/RR
Residential	0.96	0.98	0.97	0.94	0.97
Farms	0.96	0.97	0.97	0.96	0.97
Commercial	1.03	1.03	1.02	1.04	1.03
Power	1.03	1.01	1.03	1.03	1.01
Oilfields	1.02	1.02	1.01	1.05	1.03
Streetlights	0.86	0.85	0.85	0.79	0.78
Reseller	0.93	0.94	0.93	0.96	0.94
Total	**1.00**	**1.00**	**1.00**	**1.00**	**1.00**

Any changes in R/RR ratios resulting from the methodology review need not be completely rebalanced in the next rate application. Future rate increases will weigh the desire to rebalance rates against the need to limit the maximum rate increases to any one class of customers to avoid rate shock.

Supplemental Items

As a result of issues brought forward by stakeholders, or via the natural course of the review, subsequent items for SaskPower to potentially examine were suggested by Elenchus. Although the issues raised fell outside of the contracted scope of this review, SaskPower would like to thank Elenchus Research Associates for providing insights on these issues:

1) Evaluate the potential to decrease the existing 230kV rate for Power class customers.

2) Assess the potential to increase the Time-of-Use (TOU) energy differential from its current level of 1 cent/kwh.

3) Using forecasted versus historic capacity and energy payments for the classification of Power Purchase Agreement expenses between energy and demand.

SaskPower's Response

SaskPower continues to examine these items and will provide a separate response to stakeholders when completed.

Appendix A – 2017 Cost of Service Review Requirements, Recommendations and Potential Impacts

Requirement	Elenchus' Recommendation	SaskPower's Position	Impact Description
Review current Equivalent Peaker Method	Change to Average and Excess methodology	Agree – will implement at next scheduled rate application	Will shift more generation asset costs to energy, impacts high load factor customers
Review Minimum System Method	Implement Minimum System Method	Agree – will implement at next scheduled rate application	Will shift more distribution costs to the basic monthly charge; improves SaskPower's fixed cost recovery, negatively impacts low energy users and streetlights
Examine current Winter & Summer allocation (2CP) factors	No changes recommended	NA	None
Identify main classification and allocation methodologies (surveys)	SaskPower is in compliance with industry standards	NA	None
Examine current functionalization of overhead costs	No changes recommended	NA	None
Examine current coincident and non-coincident peak allocators (load research program)	Replace existing NCP demand with MDD for allocation purposes	Agree – will implement at next scheduled rate application	Affects allocation of distribution transformer costs only; Farms and Residentials slightly gain, Commercial and Oilfields slightly lose ground
Review current existing rate design methodology	No changes recommended	NA	None
Compare existing methodologies with other jurisdictions (surveys)	SaskPower is in compliance with industry standards	NA	None
Examine proposed customer class consolidation strategy (rate simplification)	No changes recommended	NA	None
Examine current treatment of Demand Response program in COS	No changes recommended	NA	None