0:0:0.0 --> 0:0:29.850
Scott Chomos
For privacy reasons, I want to advise that the session is being recorded for future reference and clarity as required. The recording will be stored on the cost of service methodology review web page at www.saskpower.com. It will remain on this site until it is no longer serving a business purpose and or has met its retention period. By staying in the teams meeting you are consenting to being recorded for the purposes outlined after the session. The link to the recording will be shared once it’s downloaded and saved as will a copy of this presentation, so it'll be, again, on that cost of service website.

0:0:40.860 --> 0:0:57.410
Scott Chomos
Today, we'd like to acknowledge that this meeting is hosted from the traditional territory of the Treaty 4 Nations and the home of the Metis. We make this acknowledgement and the spirit of reconciliation because we are all treaty people as we each make our homes in the traditional territory of the Indigenous people of Canada.

0:1:0.170 --> 0:1:9.300
Scott Chomos
For those of you that have participated in a SaskPower-related meeting in the past too, you'll also recognize the fact that we like to start meetings with safety moments. Because we're in this spring period where, it's just inevitable, especially here in Saskatchewan, that these significant windstorms can pop up out of the blue. We're going to talk a little bit about what to do in case you come across a fallen power line. So again, always assume that wires are energized. Stay at least 10 meters away and call 911 and never try to move a downed power line on your own. If you happen to be in a vehicle similar to the image on the screen, first and foremost, stay inside your vehicle. If it's not safe to stay inside. Keep your feet together and hold arms tightly at your sides. Jump clear without touching your vehicle and finally hop away from vehicle with feet together once it's safe to do so.

0:1:58.50 --> 0:2:28.320
Scott Chomos
Finally, I think I am going to turn it over to John and Andrew shortly. Before I do though, I just wanted to recognize a few other individuals who are participating on the call today. First, we have the Saskatchewan Rate Review Panel Chair and Vice Chair, Mr. Albert Johnson and Dwayne Hayunga, as well as a number of other board or panel members participating today. And we've also got Gerry Forrest, one of the technical consultants for the rate review panel. And finally, I would just like to thank everybody who's primarily our most important customers for taking the time today and having a listen to what John Todd and Andrew Blair from Elenchus are going to discuss with us today in terms of their review of SaskPower’s current cost of service rate design methodologies.

0:2:53.830 --> 0:2:55.250
Scott Chomos
So I think with that, I see Andrew on the screen, so maybe I'll start by turning it over to Andrew.

0:3:2.940 --> 0:3:8.910
Andrew Blair
Alright hello everyone. Welcome to the third public meeting of the 2023 cost allocation and rate design review. Go to the next slide, please.

0:3:13.800 --> 0:3:26.710
Andrew Blair
We'll start with a brief description of the project and background on cost allocation methodologies. We'll move on to our review and recommendations. Then we'll go to a summary and a selection of the survey responses and discuss next steps. The next slide please.

0:3:30.760 --> 0:3:36.380
Andrew Blair
I’m Andrew Blair, a senior consultant with Elenchus and John Todd, the president of Elenchus, is also here today. John founded Elenchus over 40 years ago and has worked with utilities, regulators and consumer groups all across Canada.

0:3:44.700 --> 0:3:50.910
Andrew Blair
Elenchus previously reviewed cost allocation and rate design methodologies for SaskPower in 2012 and 2017. The next slide please.

0:3:55.840 --> 0:4:6.840
Andrew Blair
So our task is to review SaskPower’s cost allocation methodology and examine the functionalization classification and allocation methodologies across Canada and a couple of utilities in the United States as well. Following that review, we're making recommendations to SaskPower, which were provided in a draft report that was circulated last week. And so today is the presentation and the final report will be submitted on June 30th. Next slide.

0:4:22.760 --> 0:4:37.630
Andrew Blair
We're going to start with the background and cost allocation methodologies. This is mostly what we've gone through in previous meetings and we plan to go through this session relatively quickly because we expect most of you here today joined us in previous meetings. But please raise your hand or ask any questions if you like to go anything in more detail. So here's a schematic of SaskPower’s electricity system.

0:4:42.790 --> 0:4:56.960
Andrew Blair
From the generation system on the left due to the high voltage grid to substations and a few more levels of radial lines and voltage stepdowns that substations and transformers as it reaches end use customers at the distribution level. At the top of the image you can see the different types of equipment and how it is all functionalized from generation to transmission to distribution and then to customer services.

0:5:9.440 --> 0:5:13.10
Andrew Blair
These are the four functions that SaskPower’s assets and cost are organized into. Lower down the schematic to the right, we see the different types of customers, different rate classes that are served at different voltages.

0:5:21.810 --> 0:5:26.360
Andrew Blair
Customers only pay for the parts of the system they use, so a large industrial customer there is connected directly to the transmission system, so they do not pay any distribution costs. There are also losses. Each step along the way, and those losses are attributed to the parts of the system that each customer class uses. It's generally pretty easy to attribute specific assets and costs to these functions, but a bit more difficult for general assets like SaskPower's head office or administration costs.

0:5:49.580 --> 0:5:50.250
Andrew Blair
Next slide. There's some differences in cost allocation methodologies used by different utilities, but there are some common attributes and principles. If cost can be directly attributed to a specific class, they are. But that's pretty uncommon. Street lighting equipment can be attributed to the street lighting class, so they're directly allocated the most assets and cost are shared among classes.

0:6:12.70 --> 0:6:15.480
Andrew Blair
The main criterion for allocating cost is cost causality. Who is causing the cost to be incurred? Who is consuming electricity that needs to be generated, or who is consuming electricity at peak times and creating the need for capacity investments?

0:6:25.410 --> 0:6:38.320
Andrew Blair
The goal is fair and reasonable rates, so it costs money to provide electricity to customers across the province, and if those costs aren't covered from the customers that are causing the costs, then they're being recovered from customers that aren't causing the costs and we want to avoid that situation. So the next slide.

0:6:42.580 --> 0:6:48.170
Andrew Blair
At the three steps in cost allocation are first functionalization and classification and allocation. The first costs are grouped by function. Those functions are assigned to cost drivers, which is the categorization and classification stage, and then those costs are allocated to classes based on each class's share of those cost drivers.

0:7:3.530 --> 0:7:4.710
Andrew Blair
Next slide. So functionalization is the first step in grouping similar assets and expenses. These groupings are generally aligned with SaskPower's system of accounts. Before the functions I mentioned earlier, generation, transmission distribution and customer service are then further divided it into subfunctions. Next slide.

0:7:26.370 --> 0:7:36.990
Andrew Blair
As I mentioned earlier, different functions can apply to different customers. The transmission system connects to certain large industrial customers, but also please into distribution system that serves other customers. Next slide.

0:7:41.800 --> 0:7:43.660
Andrew Blair
The second step is classification. Cost can be classified as a demand related, which is to meet peak capacity or peak demands. They can be classified as energy related or a customer related. It's common for part of an asset or expense to be split between multiple classifications. For example, the cost of a lower voltage distribution line is driven in large part by the number of customers the lines need to reach, but the lines also need sufficient capacity for everyone to be able to get electricity when they need it. So part of the cost is also driven by peak demands. The low voltage lines subfunction is classified partially to generated and then partially to customer related. And similar for generation. It is also split between demand and energy. For the next slide, please.

0:8:36.740 --> 0:8:47.50
Andrew Blair
The classified costs are then allocated to SaskPower's customer classes, by each class's relative energy consumption or demands, or the number of customers, or in some cases the weighted the number of customers. And this gives us the total cost allocated to each customer class. So SaskPower's full annual budget is divided among rate classes and then this is compared to the revenue collected from each class. Next slide.

0:9:3.110 --> 0:9:13.320
Andrew Blair
The ratio of a class's revenues to the class's costs is analyzed and if revenues collected at current rates deviate substantially from the allocated costs, then rates are rebalanced. Theoretically, if the ratio is exactly 1.00, then the customer class is paying exactly its costs. In practice, there is some judgment in this analysis, cost allocation can be more of an art than a science so range of reasonableness is used instead of setting everything back to 1.00 every time. It would also cause breaks of fluctuate quite a bit over time. Using this range, if the ratio is lower than 0.95 or higher than 1.05, there's adjustment to bring the rates within the range. Next slide please.

0:9:50.110 --> 0:9:56.600
Andrew Blair
An important concept and cost allocation is the load factor, which is a relationship between average energy and peak demands. This graph is based on sample residential load data from 2015 and 2017. How allocating costs by electricity consumption is most relevant for fuel used in generation. Most of utilities costs are actually related to capacity. From the size of the generator to the transmission lines to substations and distribution lines, each step along the way, the equipment needs to be large enough to meet peak demands.

0:10:21.0 --> 0:10:24.370
Andrew Blair
Except the peak that's around 6:00 PM to 7:00 PM in this graph. That's what's causing a lot of SaskPower's investments to be incurred. And then the next slide.

0:10:34.380 --> 0:10:41.320
Andrew Blair
Overall, the principles underlining SaskPower's cost allocation and rate design are aligned to a set of principles called the Bonbright principles which are commonly referenced in the rate making across

North America. The attributes of sound rate structure ensures SaskPower receives an appropriate and stable level of revenue to operate. Customers pay an appropriate price based on the cost they cause and rates are set in a practical way without unnecessary complexity or controversy. Next slide.

0:11:6.30 --> 0:11:13.200
Andrew Blair
SaskPower’s stated principles are aligned with the Bonbright principles. These principles are: meeting the revenue requirement, fairness and equity economic efficiency, conservation of resources, simplicity and administrative ease and stability and gradualism. With the next slide.

0:11:26.550 --> 0:11:28.290
Andrew Blair
And I'll move on to our recommendations. Next slide.

0:11:33.620 --> 0:11:42.550
Andrew Blair
Our recommendations are based on review of other jurisdictions and review of SaskPower’s model. In addition to discussions with SaskPower’s staff and our experiences in other jurisdictions. Next slide.

0:11:47.120 --> 0:11:54.670
Andrew Blair
Overall, SaskPower follows the traditional approach that aligns with the National Association of Regulatory Utility Commissioners. NARUC, their electricity cost allocation manual and also what is being used in jurisdictions. I’ll point out that this is now our third review of SaskPower’s cost allocation methodologies and SaskPower has made a number of changes since 2012. So we're finding that there aren't substantial differences between SaskPower and other jurisdictions at this point. Next slide.

0:12:20.580 --> 0:12:26.500
Andrew Blair
This is the first review though that included a review of functionalization methods, so we'll be spending a bit more time on that. The first two studies focused on classification and allocation only. That functions are standardized across utilities. However, in jurisdictions that are deregulated, that did deregulation, broke up the utilities into the functions. So Ontario and Alberta, there are separate generation utilities, transmission, utilities and distribution utilities. And distribution utilities generally handle the customer care function.

0:12:54.110 --> 0:13:4.770
Andrew Blair
Our review focused on the level of subfunction detail. Subfunctions are generally aligned with the way utilities organize their own costs and the system of accounts or their financial statements. The next slide.

0:13:9.990 --> 0:13:13.50
Andrew Blair
Here's a summary of SaskPower’s functions and subfunctions. I will go through each of these functions separately. The next slide please.

0:13:23.270 --> 0:13:25.940
Andrew Blair
At the generation sub function has 9 sub functions. All generation, all generators are included jointly and the subfunctions are delineated by the purpose of generation rather than the source of generation. Also, notably, there are separate load and losses subfunctions. Next slide.

0:13:43.50 --> 0:13:45.190
Andrew Blair
The transmission function has four sub functions. They separated into substations and lines of different voltages. Next slide please.

0:13:54.360 --> 0:13:57.80
Andrew Blair
The distribution function has 10 sub functions. Streetlights are included as their own sub function which is directly classified and allocated to that class. There is also customer contributions included as its own sub function. The amounts in this function are attributable to the other subfunctions and are classified and allocated it in a way that offsets the associated functions. So if there is a contribution for distribution main for example that contribution is used to offset the distribution main subfunction, so it's offsetting the cost that is then allocated to the right classes. Next slide, please.

0:14:33.110 --> 0:14:50.680
Andrew Blair
The customer services function has six sub functions. The labeling of the other functions is standardized. The generation, transmission and distribution is standard across utilities, but the customer services function can take many names. Here it's called customer services, but it's also often referred to just as customer care or retail services. Next slide, please.

0:14:56.290 --> 0:15:6.40
Andrew Blair
So we have a few recommendations related to the functionalization, but they're limited to the restructuring of subfunctions and don't actually impact cost allocation or rate design results at this point. Unlike other recommendations we made, these are sort of recommendations to consider or soft recommendations. While there's some benefit to being consistent with other jurisdictions there's also a benefit to staying with the current structure because it's already well rested by SaskPower and possibly also better understood by the Rate Review Panel and other stakeholders here. Our first recommendation is to break up the load function into separate types of generation. We don't see a compelling reason to classify or allocate different types of generation in different ways at this time, but that could change in the future. So it makes sense to have separate subfunctions by different types of generation. And our second recommendation is related to the system operator functions and the system operator. Sort of in between generator and transmission. In a deregulated province, the system regulator is a separate entity from either generation or transmission utilities. And vertically integrated utilities like SaskPower we usually see the system operator as part of the transmission function, but SaskPower includes the subfunctions within the generation function. The activities of the functions are usually considered more transmission activities, so we think SaskPower should consider moving those subfunctions to the transmission function. But again, this would not impact the results and would stray

from current practice. So we're not necessarily saying it's something that SaskPower really should do, but it's something that you consider. The next slide.

0:16:34.220 --> 0:16:37.10
Andrew Blair
Moving on to classification and allocation methodologies. First we have generation which is split between demand and energy. Transmission, which is demand related, and distribution, which is a combination of capacity, so demand related, and customer related costs and customer services are always customer related. Next slide please.

0:16:59.250 --> 0:17:6.110
Andrew Blair
So taking another look at generation, fuel is a clear energy related cost, but what about the capital and other fixed costs? So there are 17 generating stations in Saskatchewan. But what drives those costs? Some amount of the cost depends on the amount of electricity being generated, but there's also needs to be enough stations and the stations need to be large enough to generate enough electricity at peak times. If everyone can see the same moment energy at all times of the day, they got flat load factor you could get away with having less generation capacity, but in reality consumption fluctuates throughout the day and throughout the year, so the generating capacity needs to be enough to meet those high demands. There's a few different ways to do this based on analysis of peak and average demands. The next slide please.

0:17:49.140 --> 0:17:51.140
Andrew Blair
So peak demands can be measured in different ways. It could be a single peak or one CP and that looks at only the highest demand hour in the year. That can fluctuate quite a bit from year to year. On the other hand, there's the 12 CP which is the sum of the peak hour in each month. So, if you look at each month individually and find the peak, you add up all 12 hours and you get the 12 CP. There are many variations in between that look at peaks for three hours or four hours or look at monthly peaks at different seasons. And other options are to ignore the monthly aspect of this calculation entirely and look at a wide range in peaks hours now. For example, one utility just looks at the top 300 peak hours of the year and they could all be in the same day. They could be a number of days in a row. They have the same day, but the peak hour is just the top 300 hours of the year. With peak with a peak demand defined the next step is to look for relationship between peak demand and average demand. Go to next slide please.

0:18:51.200 --> 0:18:54.340
Andrew Blair
There are few ways to weight energy requirements versus capacity requirements. The average and excess method looks at average demands and each rate class is peak demands. The peak demand is in excess of average demand or peak demand. The peak demand and excessive average demand is considered demand related and the remainder is considered average demand or energy related. The next one, the equivalent peaker method, starts by separating assets and costs into cost deemed to be serving peak demands and cost deemed to be serving average demands or sort of more like base load demands. Peak demands are then classified as demand related and average demands are considered energy related. The base and peak method is similar to equivalent peaker, but the method also

considers average demands as another form of sort of demand related. Then they're judgmental energy weightings, which could be as simple as saying 50% is demand related and 50% is energy related. In 2017, Elenchus recommended that SaskPower move from the equivalent peaker method to the average and excess methodology, and this change is implemented. Next slide please.

0:20:4.600 --> 0:20:11.410
Andrew Blair
So there are a few other methods that are quite complex and we don't see them used elsewhere, so we won't get too into them right now. Next slide, please.

0:20:17.130 --> 0:20:19.390
Andrew Blair
SaskPower uses the average and excess method. The costs classified as energy related or allocated to classes based on each class's share of total energy consumption adjusted for losses. And the demand related costs are allocated based on the two CP. And the two CP in this context means there is two coincident peak periods, the first being three winter months and the second being three summer months. So another way of considering it is it could be considered a six CP. And this reflects SaskPower's two peaking periods, one in the winter and one in the summer. Next slide please.

0:20:56.580 --> 0:21:4.420
Andrew Blair
Transmission costs are classified fully as demand related and this is common among utilities. Elenchus has agreed with this methodology in the past. Again, demands are allocated based on a 2CP allocator. The next slide.

0:21:14.800 --> 0:21:17.290
Andrew Blair
With distribution, there are some differences among subfunctions. Lines and transformers are classified between demand related and customer related based on the minimum system method. This method assigns certain costs attributed to reaching each customer based on a hypothetical minimum system with little to no demand, so it determines what that would cost, with this hypothetical no demand system, would cost and then any cost in excess of that are considered demand related. Then substations are classified as fully demand related. The more upstream costs like subtransmission stations are allocated based on the system peak - that two CP. But the demand related costs that are downstream and closer to customers are allocated based on a non coincident peak. This means instead of looking at the system peak time and looking at who is consuming electricity at that peak time, the peak demands of each individual class irrespective of the demands of other classes is used. And when it comes to upstream assets, it matters who else is using the system at that time. But when it comes to assess them closer to the customer, it's the demand of those closer customers that matters.

0:22:25.340 --> 0:22:29.510
Andrew Blair
SaskPower has used rounded figures for its classification lot. So ones are classified as 70% demand and 30% customer related. The results of the minimum system study indicate that lines are 68.5% customer related and 31.5% demand related, so they're just rounded to the closest 5%. And rounding is common and sometimes these types of studies are as tests of reasonableness for existing classification factors. But here we're recommending that SaskPower use the actual figures, the more specific figures so uses

the 68.5% and 31.5% instead of the 70 and 30%. If the results of the study change over time, it's fair to have the gradual change implemented over time because if it changed 1% from study to study, it would make more sense to apply that each year rather than wait a few years and then apply a full 5% change all at once. Next slide.

0:23:31.540 --> 0:23:45.980
Andrew Blair
Moving on to SaskPower's rate design methodology again, SaskPower uses the common methodology of basic, monthly basic monthly charges and energy charges for a smaller customers and basic monthly charges, energy charges and demand charges for larger customers. From an economic perspective and price signal perspective, it would be ideal to have these three charges for all customers, but in practice it's impractical to have demand meters for smaller customers. So that's why smaller customers have only the energy charge and basic monthly charge. Next slide, please.

0:24:8.930 --> 0:24:12.860
Andrew Blair
So time of use rates. SaskPower does not currently have time of use rates and this is something Elenchus discussed in previous studies, and we're including here again, because there's good economic rationale for all utilities, including SaskPower to loop to time of use rates. Time of use rates apply different energy charges at different times of the day and season. So it costs more to generate electricity at peak times and peak demands are what are driving many of SaskPower's other investments. So it makes sense to charge more at peak times and less at off peak times. It would be an effective price signal to customers to shift some consumption to off peak times. It's more effective in systems with low load factors and so we see that Saskatchewan isn't quite as peaky as some other provinces, so the benefits likely won't be as significant. But there was still be cost benefits to customers.

0:25:2.270 --> 0:25:17.110
Andrew Blair
One of the main barriers I've been implementing time of use rates is good hourly data. So following the current rollout of advanced metering infrastructure, SaskPower will have the data to set effective time of use rates and, like, get the low data needed to properly bill customers. So we're not recommending for SaskPower to adopt time use rates right now. They are not really in position to do that right now, but we encourage SaskPower to keep it on their mind and to more formally visit the concept once they have some of the better data in place.

0:25:34.580 --> 0:26:5.260
Rod MacQuarrie
Actually Andrew, if I can just jump in there for a minute. I just wanted to clarify that that we do actually have time of use rates for our power class customers, for our large industrials. We don't have them for our mass market customers such as residential and farm and commercial. And the power class rates that we do have for time of use, they actually have a very low differential on them. It's only a one cent differential between on and off peak and it's exactly for the reasons that you've outlined here because of our high system load factor, it's very hard to find a high value level between the on and off peaks because our marginal costs of energy don't change. So I just I just wanted to clarify that that we actually do have time of use rates for our large industrial customers.

0:26:17.620 --> 0:26:23.310
Andrew Blair
Right. Thank you. That's good clarification. Yeah, but for the residential customers and also our commercial customers. And those are the customers that tend to be more peaky anyway. They have higher swings in consumption throughout the day and seasons.

0:26:33.190 --> 0:26:34.510
Rod MacQuarrie
Exactly. OK. Thanks, Andrew.

0:26:36.890 --> 0:26:38.190
Andrew Blair
So next slide. We also want to note here a rate design change that occurred since the last review. A typical rate design is to recover fixed customer related costs. The basic monthly charge, demand related costs through the demand charge and energy related costs through an energy charge. But for larger rate classes SaskPower used to make an adjustment known as the coincident peak allocation methodology or the Bary correction. And this adjustment was made to the cost allocation to the cost allocated to a class, so it didn't impact the cost allocation, but impacted rate design. So it's just within the class. And it's because costs are largely driven by peak demands the demands at peak times the largest customers pay demand charges based on their highest demand each month, whether that demand was during the assistant peak or not. Customers with consistent demand or more likely to have high demands in peak times than customers with demands that fluctuate over time. So, if you consider two customers with the same monthly demand and, therefore they pay the same demand charge, charges on their total bill. It's the customer with the more consistent consumption or the higher overall consumption that it's causing more the demand cost than the customer with the lower fluctuating consumption. So they made an adjustment to shift costs to be recovered from demand charges to energy charges. This improves the intraclass equity but provided the incorrect price signal.

0:28:11.520 --> 0:28:24.590
Andrew Blair
Customers that self generated avoided these energy charges, but they're also avoiding part of the demand related costs that they were causing. So this left more cost to be recovered from the customers that didn't cause those costs to be incurred. So since 2022, SaskPower has been phasing out this adjustment. Next slide, please.

0:28:36.450 --> 0:28:40.940
Andrew Blair
So from a cost allocation perspective, the carbon tax is quite unique. It's caused by generation and essentially as a markup on fuel costs. SaskPower has been directed to include the carbon tax as a separate line item on customer bills, so it's not included in the cost allocation model and is treated more of a rate rider. SaskPower calculates the carbon tax based on losses, adjusted energy consumption of each class, and this is exactly how it would be treated in the cost allocation model if it was included in the model with fuel costs. In other jurisdictions with different allocations to fuel costs there would be a bit more detail needed to allocate costs correctly, but in SaskPower’s case with most of the generation being covering generation anyway and no significant difference in the dispatch of those fuels this

method is appropriate, so even though it's not going through the cost allocation model, if it were flowing through cost allocation model we, this would be the appropriate methodology to use. Next slide.

0:29:40.570 --> 0:29:42.330
Andrew Blair
Now on to the survey results. Next slide.

0:29:47.0 --> 0:29:50.780
Andrew Blair
We surveyed 10 utilities. Eight in Canada and two in the United States. In Canada, we surveyed one utility and each other province except PEI. And we have a selection of tables in the section and the report. But There isn’t time to go through all of them today. So we have a sort of subsection of those today.

0:30:9.440 --> 0:30:15.720
Andrew Blair
So functionalization is very standardized across North America and even more so following the transition to IFRS accounting. The functionalization and subfunctionalization of SaskPower’s costs are aligned with its system of accounts. Next slide.

0:30:27.330 --> 0:30:30.810
Andrew Blair
This table shows the number of generations sub functions used by each utility. As you can see, it's common to have two or three, but some utilities have more. SaskPower has nine sub functions which is on the higher end. But as I mentioned before, there are few sub functions that are more system operator type functions. And note that there are two utilities, ATCO and Hydro One, that don't have generation sub functions because they they're deregulated. So that's those are the two at the NA down there. Next slide.

0:31:0.940 --> 0:31:3.110
Andrew Blair
This table shows the number of transmission sub functions. SaskPower has four sub functions. And here I'll point out that all four sub functions are classified in the same way, and it's common for transmission to be fully classified as demand related. So some utilities, when they move from their financial statements to their cost allocation models, they wouldn't break it out because everything is done the same way anyway. So that's why there are so many there for there that's just the one function. It's because they're going to treat everything the same way anyway. So they just include the entire cost together as one. They don't break it out in the same way. Next slide please.

0:31:44.810 --> 0:31:48.640
Andrew Blair
Here the function and subfunctionalization results of the distribution function. Uh, there's quite a range here and SaskPower is that the upper range upper end of the range with 10. Next slide.

0:31:59.880 --> 0:32:8.750
Andrew Blair
Finally, here are the results for the customer care function. SaskPower is on the high end here with six

and that was to reflect a higher level of detail in the model. Other utilities might have subfunctions like metering and metering services and meter reading together, but SaskPower has them listed separately in the model. Similarly, there's billing and customer accounts and customer collections that are treated as one subfunction in many other utilities, but treated as two and SaskPower's. So it's really just a minor difference in the approach and there's no real right or wrong way to do it, and we don't see any reason to change even though they are a bit different from the other utilities. Next slide please.

0:32:45.820 --> 0:32:48.690
Andrew Blair
This table shows the classification methodology for generation. SaskPower is in the most common grouping here, with its average and excess being based on the system load factor. Next slide.

0:33:1.860 --> 0:33:2.780
Andrew Blair
Next slide please. Here we have the shared generation classified as demand. And SaskPower is on the lower end here, and that's because it's about 25% is the share of SaskPower's generation costs that are classified as demand. And that's because Saskatchewan has a high load factor and doesn't have significant peaks in one season. So the dual peaking in the winter and summer make it a flatter load factor overall. And so a lower share of its cost are treated as demand related. Next slide.

0:33:38.660 --> 0:33:43.790
Andrew Blair
Transmission costs as powers costs are classified as fully as demand, which is the most common. Next slide.

0:33:48.810 --> 0:33:54.490
Andrew Blair
SaskPower's classification method for distribution lines and transformers is based on the minimum system method. Note that the there are three utilities that use just the minimum system method, and then three others that you use that method along with the zero intercept method and the zero intercept method is conceptually similar, but it's just done with a different sort of calculation. So overall SaskPower is aligned with the common practice in North America. Next slide. So finally have the next steps of this process.

0:34:21.160 --> 0:34:21.950
Andrew Blair
Next slide.

0:34:23.40 --> 0:34:24.950
Andrew Blair
So today is May 17th. And we'll open the floor for some questions in a minute, but there there's a process to submit written questions by May 24th, and we'll respond to those by June 2nd.

0:34:35.520 --> 0:34:38.630
Andrew Blair
If you have pretty detailed questions that might be the best route for you. Stakeholders are invited to

write to file written submissions by June 20, June 16th. And then the final report will be delivered on June 30th. So now we'll open up for questions.

0:35:9.250 --> 0:35:13.0
Rod MacQuarrie
Does anybody have any questions? Scott, did you want to jump in and just talk about how customers can ask questions on our web page?

0:35:22.170 --> 0:35:36.760
Scott Chomos
Sure. Yeah. If there's no questions today, but if something comes to mind after and you would like to submit a written question, what this slide is showing is where on SaskPower's website where we will end up including the transcript from today. We'll have a copy of the previous cost of service study included on there and the e-mail address that you are to use is actually on the previous slide. So it's cosreview@saspower.com.

0:36:8.850 --> 0:36:12.860
Forkast
Andrew, Gerry Forrest if I could just ask. I'm referring to your draft report that you circulated and particularly the tables at page 53, 54 and so on where you summarize the various allocation methodologies that are used in across Canada and into US utilities. The question I was going to ask you, and I'm just suggesting this for ease when people are looking at this report in the long term that you add at the bottom of them SaskPower's current methodology and each one of those items.

0:36:52.500 --> 0:36:54.750
Andrew Blair
Sure, that's good point. I'll add that.

0:36:56.410 --> 0:37:10.10
Forkast
And then if I could just follow up on Rod in your comment on the question of time of use rates, any cost or benefits associated with the current program, Rod, that you have in place all of those costs and benefits are contained in those particular customer classes. None of the cost or benefits flow to any other class of customer.

0:37:23.160 --> 0:37:24.490
Rod MacQuarrie
That is correct, yeah.

0:37:29.170 --> 0:37:36.810
Forkast
Thank you, Rod. Then if I go to your specific recommendations, Andrew, particularly the first one where you're suggesting that you break out the load into separate functions in the future. Can you give me the sort of an outline reason why?

0:37:56.210 --> 0:37:59.310
Andrew Blair
So we see that the breakout in other provinces and sometimes costs are allocated or they're classified

differently based on different types of generation. If there's sort of decisions on what is dispatched at different times then it would make sense to have the separate types of generation laid out so that certain generation would be classified more towards average demand and the more peaking plants would be classified as demand related instead.

0:38:28.140 --> 0:38:28.810
Forkast
So you're.

0:38:28.50 --> 0:38:34.910
Andrew Blair
And this it also would be, could be useful for setting time of use rates to have the different costs or laid out more seasonally and more at different times of the day.

0:38:41.180 --> 0:38:47.830
Forkast
And you think that would give better signals for SaskPower to use in the future when they're allocating costs?

0:38:51.510 --> 0:38:57.400
Andrew Blair
Yes, if would be good to know. I know SaskPower is definitely aware of the different costs of different types of generation, but it could be still have that more laid out and how that is allocated to different classes and different types of generation might be allocated to different classes in different ways.

0:39:10.610 --> 0:39:17.370
Forkast
Yeah. I guess what I'm just trying to determine in my own mind, when I look at these kinds of studies for, for your purposes of fairness and reasonable rates for the future, the question is, is this going to help or are we trying to determine how many angels can dance on the end of the pin?

0:39:32.600 --> 0:39:40.180
Forkast
In other words, are we trying to get too much refinement out of this issue, or is it really important in the cost of service methodology going forward?

0:39:43.300 --> 0:39:48.670
Andrew Blair
I'll say it's not important at this time, so it's not really necessary to do this right now. But if there was a decision to change the classification in the future, even SaskPower knowing that they they're capable of doing it, which it sounds like they are, they could implement this if necessary but it's not something that needs to be done.

0:40:6.440 --> 0:40:8.810
John Todd
Can I can I add to that Andrew? John Todd. Part of what we do, Gerry, is in reviewing other jurisdictions, other companies it is sort of getting a sense of what may happen in the future.

0:40:23.570 --> 0:40:23.960
Forkast
Right.

0:40:23.770 --> 0:40:27.80
John Todd
Right now it's irrelevant really for SaskPower. As the market changes and in some of the markets have changed more already in terms of competitive pressures and so on then SaskPower. Then the refinements may become relevant for SAS power as well as it changes And the reason for the comment is if five years from now, the next review it becomes relevant to have the more refined approach. If it's in place, it makes it easy to do and it can be make no difference in the mean time. But if it's required, by anticipating the possibility, it's there and ready to draw on if you need it in five years, assuming you know our view every five years. Otherwise, it may be five years before recommendation in 10 years before you have the refinement. So it's a, I guess, it's a nice to have just in case it matters in the future and you would have it on a more timely basis. But I think from today's perspective, it probably is angels dancing on the head of the pin.

0:41:41.630 --> 0:42:11.480
Forkast
John, I very much appreciate your comment as we chatted at the last one. This is exactly the kind of thoughts I was hoping would get from you in the cost of service review because this industry is going through a massive change and any further data that can be gathered and gathered appropriately will help insofar as plotting a plan going forward. So I don't want to take the comments that I made to Andrew as negative. I'm just trying to get an understanding what he was trying to do and why. And I got that. So I appreciate the answer there in so far as that and I'm just trying to get to also some clarification on some of the recommendations that you have here, where you're talking about scheduling, dispatch, regulation and frequency moving it out of generation and into transmission. Again, I'm just trying in the back of my mind trying to understand the reasons for that going forward. Is that also sort of a refinement in ensuring that you have the data points in the future if you're going to change direction on the cost of service study.

0:42:54.290 --> 0:43:4.150
Andrew Blair
That's similarly, it's just more for the future. What one thing is too, if you want to compare the share of costs that relate to generation and transmission and distribution. Just knowing that those costs are included in different categories elsewhere would be helpful for that analysis. And if again with the way, the way some provinces are changing and the industry is going, that these specific functions are often not even included in the utility. They are a separate entity.

0:43:25.980 --> 0:43:26.300
Forkast
Yeah.

0:43:26.590 --> 0:43:38.940
Andrew Blair
Getting include those together and more aligned with where we see this, often transmission and system

operator is the name of the function rather than just transmission. So I think lining it up with the other problems is that we reviewed Some logic to it in that perspective.

0:43:43.140 --> 0:43:54.180
Forkast
Right now, John, you're obviously online here. When I, I'm reflecting in the past where we used to do this where we would have phase one, which is the cost of service study itself and the review of it. And then we'd go just phase two, which was rate design. In your report, you don't deal with rate design in any significant way. You've dealt with it with respect to the three components, but you know, I guess one of the questions that I had in the back of my mind is a great deal of the cost to the consumer today is a blended rate between those that are on the customer charge and energy charge. Is there a thought that in the long term we should have more clarity on the customer cost side and how much we're going to generate revenue in the blended rate relative to what that fixed cost component actually is. Has there been any thought or have you given any thought to that matter?

0:44:52.160 --> 0:44:53.410
John Todd
Jerry, as usual, you ask questions where you know the answer, and want to share it with the rest of the group. And by the way, in that vein with these questions and any questions that other parties submit after the fact, the questions and responses will be included in the final report. I mean for these questions, there's a transcript. So it'll be including the transcript of this discussion. Any questions will be documented for clarification purposes in the future. As to your question and when we were talking about it early in the process and technically this is a cost of service review and rate design is out of scope.

0:45:39.920 --> 0:45:40.810
Forkast
Yeah. OK.

0:45:40.950 --> 0:45:52.990
John Todd
We considered it relevant and SaskPower accepted that we pushed the boundaries on that little bit. You can discuss your time, use rates and what you raise is issues that are very important in the industry generally. We are involved actually in a couple of other proceedings across the country that are struggling with some of the right design issues. They are, the considerations uh, customer focus, impacts on customers, industry structure, all those factors that are relevant get, you know, drill down into a lot of detail and Rod may want to speak to or Scott to the fact that I know SaskPower is doing a lot of thinking about these issues. For example, the CRS rate process that was that now around a couple years ago, I mean that was a rate design issue.

0:46:50.310 --> 0:46:50.740
Forkast
Right.

0:46:51.10 --> 0:47:0.100
John Todd
And they are very concerned, as is everybody in the industry, including us, about how we evolve the

design of rates in order to encourage efficiency, to create better signals to customers, is how they cause costs and some of those changes are dependent upon the technology for recording electricity use and for billing. So, for example, the theoretically ideal rate structure has a customer charge which recovers the customer related costs and energy charge recovers the energy costs and the demand charge recovers demand related costs for all classes.

0:47:39.600 --> 0:47:42.830
John Todd
At the present time of SaskPower and most other utilities across the country do not have, do not record demands, peak demands of customers in the smaller customer classes, just the metering doesn't do that. With the implementation of AMI, that capability is coming. When you go down some of these paths, there can be very significant impacts on customer bills. I instead shifting cost responsibility. That makes changes complicated issues. So I guess what I'm saying is that I hear your concerns. SaskPower hears your concerns, it's sort of out of scope. But I'm sure those kinds of issues will be, further discussion between the Rate Review Panel and SaskPower, and who knows, maybe us, on dealing with some of these issues because the pressures are there to create these changes. And one of the things we're observing is when there are changes in one province people in other provinces see that and there at least some customers who say, huh, we should be following suit. And there's, you know, good reasons for those changes. So in terms of this report, I'd have to say we scratched the surface. But your comment raises the point that this will be a future issue for SaskPower and the Panel.

0:49:20.660 --> 0:49:21.680
Forkast
Thank you, John.

0:49:21.0 --> 0:49:21.790
John Todd
In my view.

0:49:23.410 --> 0:49:40.350
Forkast
I really appreciate it. Maybe Rod can give us some further highlights of what they're thinking of in the long term to help us and help the Panel particularly because they're recognizing more so than ever that the future is less clearer than certainly the past.

0:49:42.540 --> 0:50:13.620
Rod MacQuarrie
Yeah, that's correct, Gerry. And I think I think John hit it on the head here that technology and data are going to be key factors for us going forward in terms of our ability to design more, more types of rates, more innovative rates, time of use rates potentially. And that's why we are very much looking forward to our AMI project being completed and getting all of that data consolidated together. And so we're able to do some testing to try and do exactly that, to sort of test the water, so to speak, and see what exactly we can do in terms of designing new innovative rates. And then and also being cognizant of the impact that these rates can have on certain jurisdictions, so, you know, for example, it was mentioned that we, utilities generally don't have demand rates for low usage customers and you know the reason for that is that in a perfect world everybody would be on a demand meter. But there's there some reasons why we don't do it. And one of them is that demand rates can be very, very punitive to low load factor

customers, low usage, low load factor customers. So the trick is how do we design the rate that can provide those price incentives recover adequate costs, but not be overly punitive to these customers who are just you know, they're peaky, they're consumption is all over the map, they're not using a lot. How do we do this? And that's really the challenge that we're facing and like and it was mentioned before, I think everybody is facing it at this point. And I think once we get our AMI data and we can really see what's going on, we can drill down into those classes and see what's happening. I think we're going to be in a much better position.

0:51:31.440 --> 0:51:32.710
Forkast
It right, that's it.

0:51:33.170 --> 0:52:2.220
John Todd
Oh, so I I'd flag that with Rod's comments that he touched on. I want to highlight that the solution to the issues that need to be addressed are not purely technical. You know, for example, one of the rationales for not having demand charges over small volume customers and we led a process I think it was ten years ago or more at the Ontario Energy Board looking at demand charges for low volume customers just when Ontario was getting into smart meters. But there's customer diversity, and if you got customers diversity and you thinking of customers as a class, is it appropriate? Is it conceptually appropriate to have a rate where customers pay for their individual peak demand when the system, in a sense only has to respond to aggregate demand, peak demand. Or on individual feeders at least, and things like that. It's so it's not… in a simplistic way, there are simplistic solutions, but when you actually think about it more deeply some of those apparently straightforward solutions don't make sense. And that's why I was trying to be very cautious in the previous comments that these things have to be considered, but what's being done elsewhere is necessarily an appropriate example for SaskPower. And all across North America around the world, these issues are being struggled with and I think I have to say that the solutions that people are coming up with across jurisdictions differ. And there's conflicting views as to what is the right thing to do.

0:53:21.600 --> 0:53:50.590
Forkast
Hey John. You and Rod both have the this in hand. All I'm trying to illustrate to all here that the future on all of these issues is complicated. There's probably no simple one solution to all but it's really important that everyone understands that there's clarity in the cost of serving and, two, the services that they acquire on a day-to-day basis. It's just important to them to know so they can take whatever action if you as appropriate, but at the same point in time, then they know that if they're going to go for supplemental generation or whatever, what the cost and benefits of that is going to be to them personally.

0:54:6.40 --> 0:54:6.750
John Todd
Absolutely.

0:54:12.790 --> 0:54:31.970
Forkast
Great job, John, Andrew and Rod, certainly from my point of view and the report is very helpful and

certainly in the panel I expect will be following the questions back and forth and indeed if it would be possible to ensure that the panel was made aware of the significance of the questions that may be post going forward.

0:54:39.650 --> 0:54:41.350
Rod MacQuarrie
OK. Does anybody have any questions?

0:54:51.580 --> 0:54:54.890
Scott Chomos
Well, I was just going to say that if there are no further questions, you know, I'm sure nobody will mind getting a little bit of time back into their day, so again, I think on on behalf of SaskPower and Elenchus, we'd like to thank you for your time today to listen to the findings in the review of our cost of service methodology and why don't we just advance one last time, Rod and we'll just show exactly. There's the e-mail address. If you do have a further question, COSreview@saskpower.com and any additional information that came from today's meeting or from previous discussions can be found on Saskpower as website. Advance one, Rod.

0:55:39.900 --> 0:55:40.330
Rod MacQuarrie
That's it.

0:55:41.980 --> 0:55:42.740
Scott Chomos
OK.

0:55:42.980 --> 0:55:44.110
Rod MacQuarrie
Yep, we're done.

0:55:45.540 --> 0:55:52.590
Scott Chomos
Yeah, there it is. There on hitting accounts and then going on to the right hand side onto the cost of service page.

0:55:53.970 --> 0:55:58.160
Forkast
Andrew, can you forward me a copy of the presentation you had today?

0:55:59.720 --> 0:56:0.100
Andrew Blair
Sure.

0:56:1.350 --> 0:56:2.80
Forkast
Appreciate that.

0:56:9.500 --> 0:56:9.970
Rod MacQuarrie
All right.

0:56:8.810 --> 0:56:11.910
Scott Chomos
OK. Thanks, everybody. We'll see you again soon.

0:56:12.620 --> 0:56:12.880
Rod MacQuarrie
OK.

0:56:14.180 --> 0:56:15.410
Rod MacQuarrie
Thanks Andrew. Thanks John.

0:56:15.330 --> 0:56:15.840
Forkast
Thank you.

0:56:16.430 --> 0:56:16.890
Kaare Svidal
Thank you.

0:56:16.190 --> 0:56:17.100
John Todd
Bye. Pleasure.

0:56:16.870 --> 0:56:17.490
Rod MacQuarrie
Yeah. Take care.