COMPLETE RESPONSES TO INTERROGATORIES FROM THE SASKATCHEWAN RATE REVIEW PANEL

[2026 and 2027 Rate Application]

SaskPower
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1. Reference: Application

a) Please provide the date of the business plan that forms the basis of the application and identify the date of any updates to that business plan included in the application.

b) Please summarize any changes to SaskPower's chart of accounts or accounting treatments since the last rate application and advise of any resulting issues in comparability of figures between the last rate application and the current rate application.

c) Please describe the changes in accounting treatment of information technology costs discussed on page 26 of the application and identify the impact on operations and maintenance costs and capital costs in the test years.

2. Reference: Application

a) Please provide a graph which illustrates the actual and proposed percentage increases for each major customer group from 2017/18 through 2026/27 similar to the response to SRRP-Q2 from the first round interrogatories from the 2022 and 2023 Rate Application.

3. Reference: Application

a) Please provide a schedule showing SaskPower's total domestic electricity sales revenue; operating income; return on equity, debt to equity ratio, revenue lift and percentage rate increase for 2025/26 and 2026/27 assuming each of the following potential rate scenarios:

   i. Confirmation of the 3.9% average rate increases effective February 1, 2026 and February 1, 2027 as applied for;
   ii. Confirmation of 2% average rate increases effective February 1, 2026 and February 1, 2027;
   iii. No rate increases in 2025/26 or 2026/27;
   iv. Equal percentage rate increases effective February 1, 2026 and February 1, 2027 that achieve the long-term target ROE of 8.5% in the 2026/27 fiscal year.

v. Equal percentage rate increases effective February 1, 2026 and February 1, 2027 that achieve an ROE of 6.0% in the 2026/27 fiscal year.
vi. Equal percentage rate increases effective February 1st each year for five years that achieve the long-term target ROE of 8.5% by the final year.
vii. Equal percentage rate increases effective February 1, 2026 and February 1, 2027 that achieve a 75% debt ratio by the end of 2026/27.
viii. Equal percentage rate increases effective February 1st 2026 and each subsequent year for five years that achieve a 75% debt ratio by the final year.

b) Please discuss why SaskPower elected not to file a three year rate application given that the application was filed more than 9 months into the first test year.

c) Please provide estimated debt ratios, ROE percentage and operating income in 2027/28 assuming:

i. No further rate increases in 2027/28.
ii. An additional 3.9% rate increase effective February 1, 2028.

4. Reference: Application

a) Please provide a continuity schedule of Plant in Service and Total Property, Plant and Equipment by function (generation, transmission, distribution, general) for the three most recent actual years and forecasts for 2025/26 and 2026/27 similar to the response to SRRP-Q5 from the first round interrogatories from the 2022 and 2023 Rate Application.

5. Reference: Work from Home Policies

a) Does SaskPower have a work from home policy? If so, please provide a copy. If not, please discuss why not.

b) What proportion of SaskPower's workforce works from home either part-time or full-time.

6. Reference: Artificial Intelligence

a) Does SaskPower have an artificial intelligence use policy? If so, please provide it. If not, please explain why not.

b) Please discuss how SaskPower currently uses AI and what additional applications it anticipates in the test years.

7. Reference: Affordability:

a) Does SaskPower have a working definition of bill affordability or energy poverty? For example, a Low-Income Cut-Off (LICO) threshold used to identify households who may need assistance with their bills or who may benefit from support implementing energy efficiency measures?

b) Does SaskPower have bill payment or bill assistance programs for low-income customers or customers having difficulty paying their electricity bills? If so, please provide a description of any existing programs and the approximate number of customers who accessed the programs in each of the past three years.

c) Please provide SaskPower's actual bad debt for the past three years and forecast for the test years.

d) Has SaskPower noticed an increase in bad debt and/or accounts in arrears in the past three years? Please discuss and quantify to the extent possible.

e) Please provide a summary of SaskPower's collection practices including policies for disconnecting or load limiting customers in arrears.

8. Reference: Payments to the Province and section 7.0 of the Application

a) For the period of 2021/22 through 2026/27 please provide a table itemizing all actual or forecast payments to the Province of Saskatchewan including water rentals, corporate capital taxes, coal royalties, dividends and any other payments to the Province.

b) SaskPower states that the application is based on the principle that "…SaskPower must set rates that will collect sufficient revenue to recover all reasonable costs and to provide a return to the shareholder." Please discuss how SaskPower's application is consistent with this principle given that SaskPower is proposing rates for 2025/26 that are forecast to result in a net loss of $147 million in 2025/26.

9. Reference: Corporate Risks

a) Please update the response to the Round 1 SRRP Q7 from the 2022 and 2023 rate application indicating what SaskPower considers to be the largest business or financial risks it faces (e.g. natural gas prices; interest rates; sales growth or decline) and provide an estimate of the potential upper and lower range of effects of these risks on operating income, return on equity and debt ratio in 2025/26 and 2026/27.

b) Please provide a separate version of the response to a) which includes the potential impact of losing one of SaskPower's largest industrial customers.

c) Does SaskPower consider cybersecurity vulnerabilities to be a material business or financial risk? Please discuss why or why not.

d) Does SaskPower consider US tariffs to be a material business or financial risk? Please discuss why or why not?

e) With reference to the federal government's engagement on strengthening industrial carbon pricing announced in December 2025 (see: https://www.canada.ca/en/environment-climate-change/news/2025/12/government-of-canada-launches-engagement-to-strengthen-industrial-carbon-pricing-and-secure-major-clean-energy-investments.html) please discuss if SaskPower views carbon pricing as a material business risk, particularly given the decision to re-power coal generation. Please discuss including any mitigation measures considered by SaskPower.

10. Reference: Carbon Charges

a) With reference to the federal carbon tax variance account (FCTVA) described on page 34 of SaskPower's 2024-25 annual report, please:

   i. Provide a breakdown of the federal carbon charge cumulative payments/payables of $1,114 million that have been:
      - remitted to the Government of Canada

- remitted to the Province of Saskatchewan
- remain as payables in SaskPower's accounts
- any other treatment.

ii. Provide a breakout of the "other recoveries/expenses" between interest and carbon charges associated with exported generation.

iii. Explain why the balance in the FCTVA is not included in SaskPower's financial statements if it reflects actual revenue collected and payables recorded by SaskPower.

iv. Quantify the amounts paid to certain independent power producers and explain the rationale for making such payments.

v. SaskPower's annual report indicates a cumulative undercollection of approximately $8 million at the end of 2024/25. Given SaskPower has paused collection of the carbon charge rider, does SaskPower intend to collect that amount from customers in the future?

b) Please provide a table that shows, by each actual and forecast year, the carbon charge revenues from each of the federal government and the provincial government that have been returned to SaskPower through grants or other mechanisms.

c) SaskPower's 2024-25 annual report states at page 14 that "effective April 1, 2025 SaskPower paused the collection of the federal carbon charge rate rider as mandated by the Government of Saskatchewan." Please provide a copy of the direction from the provincial government mandating the pause in collection of the federal carbon charge rate rider.

d) SaskPower's 2024-25 annual report states at page 14 that "SaskPower's electric heat relief program delivered $2.1 million in savings to residential and farm customers who must rely on electric heat through a 60% reduction in the federal carbon charge that was collected on their power bills between November 1, 2024 and March 31, 2025." Please:

i. Provide a description of what customers were eligible. Was it any customer with electric heat or only customers who do not have access to natural gas?

ii. Explain how the 60% reduction was calculated.

iii. Discuss if SaskPower develop this program on its own or if it was directed or mandated by the provincial government?
iv. Please explain how these reductions are reflected in the schedule provided in the response to part (a).

e) SaskPower's 2024-25 annual report states at page 34 that in July 2023, the Government of Canada approved the Saskatchewan Output-Based Performance Standards (OBPS) as a replacement for the Federal OBPS Program retroactive to January 1, 2023. Please provide a copy of the program details and the specific approvals received from the Government of Canada.

f) SaskPower states at page 6 of the application that it assumes the OBPS will not apply to the Corporation starting in 2026-27. Please discuss the basis for that assumption and provide an update on whether SaskPower continues to believe the assumption is reasonable.

g) Is SaskPower aware of any other electric utilities in Canada who are exempt from OBPS or equivalent provincial program requirements? If so, please provide details.

h) Please provide an estimate of the OBPS charge that would apply in 2026-27, 2027-28 and 2028-29 if the same basic framework were in place as for 2025-26, adjusted for anticipated changes in the carbon price and SaskPower's generation mix. Please show the calculation including assumed carbon prices, generation mix and carbon intensity per generation type.

i) SaskPower's application states at page 19 that the anticipated OBPS carbon charge in 2025-26 will be $368 million. Please discuss:

i. What portion of that amount has already been remitted to the government? If any amount has not yet been paid, please indicate when SaskPower anticipates it will be paid.
ii. Please provide the calculation of the $368 million based on SaskPower's generation mix and showing the carbon intensities by generation source and the carbon charge per unit assumed in the calculation.

11. Reference: Grant Funding

a) Please provide any documentation, direction, or guidance received regarding the Clean Electricity Transition Grant (CETG).

b) For each of the 2022-23, 2023–24, 2024–25, 2025–26, and 2026–27 fiscal years, please provide a schedule that:

i. Identifies all sources of actual or forecast grant funding, including but not limited to the CETG.
ii. Lists each grant individually by source, the amount received, and the specific purpose or activity it was intended to support.
iii. Shows where each grant is reflected in the financial statements, including the specific revenue, OM&A or capital line items or cost categories in which grant funding has been applied. Please provide a clear mapping of grant dollars to OM&A and capital expenditures.
iv. Reconciles the total OM&A and capital grant funding noted in the 2024–25 Annual Report funding referenced in the 2026–27 GRA.

12. Reference: Financial/Productivity Indicators

a) Please provide a schedule that shows the calculation of SaskPower's actual and forecasted interest coverage ratio for each of the years in the table on page 33 of the application.

13. Reference: Business Plan Assumptions

a) For each of the business plan assumptions shown in the table on page 33 of the application, please discuss the information or sources SaskPower considers in developing these assumptions.

14. Reference: Finance Charges

a) Have there have been any changes to SaskPower's debt strategy with respect to how much short-term versus long-term debt SaskPower takes on and the mixture of floating rate debt versus fixed rate debt SaskPower considers to be optimal since the response to the Round 1 SRRP Q13 from the 2022 GRA proceeding? If so, please provide a summary of the changes and an explanation of the rationale for the changes.

15. Reference: Finance Charges

a) Please provide a schedule showing all long term debt (including any long-term lease obligations) including the date of issue, date of maturity, effective interest rate, coupon rate, par value, unamortized premium, and outstanding amount for each of the last three actual years and forecasts for the test years.

b) Please provide a schedule showing SaskPower's debt in relation to the total debt of the Province of Saskatchewan for each of the last three years.

16. Reference: Finance Charges

a) For each year of the ten most recent actual years please provide a schedule showing the forecasted short-term and long-term interest rates for new debt from the prior year's business plan (i.e. the last business plan prepared before the start of each fiscal year) and the actual average effective short-term and long-term interest rates for new debt.

17. Reference: Finance Charges

a) Please provide a schedule showing details of the total finance charges for the five most recent actual years and forecasts for 2025/26 through 2026/27 including interest on long-term debt, interest on short-term debt, leases, interest capitalized, debt retirement fund earnings, and other finance charges.

18. Reference: Finance Charges

a) SaskPower states on page 28 of the application that it contributes at least 1% of the face value of certain outstanding debts annually to debt retirements funds administered by the Government of Saskatchewan. Please:

   i. Explain which debts have debt retirement funds associated with them.
   ii. Describe any circumstances where SaskPower contributes more than 1% of the face value.

iii. Explain whether or not the Government of Saskatchewan requires the debt retirement funds through legislation or policy and if so, provide a copy of the relevant legislation or policy.

iv. Provide details of the actual and forecasted debt retirement fund balances, earnings, contributions and average returns for the five most recent actual years and forecasts for 2025-26 through 2026-27.

b) Has SaskPower updated the analysis conducted in February 2020 described in the response to first round interrogatory SRRP-Q18 (b) from the 2022 and 2023 rate application? If so, please provide a summary of the updated analysis.

19. Reference: Depreciation and MFR Tab 8

a) Please confirm that the most recent external depreciation study is from 2023 and provide the proposed timing for the next external depreciation study.

b) Would SaskPower consider commissioning a version of the next external depreciation study that could be made public?

c) Did SaskPower accept and implement all of the proposed changes to average service life estimates recommended by the external consultant? If not, please explain which recommendations were not accepted and why.

d) With reference to the statement on page 1 of the rate application that states “SaskPower is continuing its work on extending the life of up to 1,530 MW of existing coal-fired generation assets by 25 years, eliminating the significant capital investment needed to construct new natural gas generation facilities over the same horizon”, please discuss whether SaskPower has reflected any impacts of the coal generation life extensions on the current depreciation rates for the existing coal units. If yes, please describe any adjustment and quantify the impact on depreciation expense. If not, please explain why not.

e) With respect to the table on page 27 of the application, please provide an explanation for the $51 million in “amortization of right-of-use assets” including a list of the right-of-use assets.

f) Please provide a table that quantifies the impact of any and all changes SaskPower has made to its depreciation rates by depreciable property group since the time of the last rate application.

g) Please discuss whether or not SaskPower's current depreciation rates include a provision to true-up or amortize variances between booked depreciation and forecast depreciation at proposed depreciation rates?

h) Please describe SaskPower's process for reviewing and revising its depreciation rates between external depreciation studies.

i) Please confirm if SaskPower's auditor has reviewed and accepted all changes to SaskPower's depreciation rates for financial reporting purposes.

20. Reference: Decommissioning and Disposal of Assets

a) Please discuss how SaskPower plans for the decommissioning and disposal of assets, in particular generation assets.

b) Are decommissioning requirements considered when selecting new generation resources? Please discuss.

c) Please discuss how SaskPower addresses refurbishment, reuse, or recycling of materials during decommissioning. In particular, are some types of generation assets more easily reused or recycled than other types of generation assets?

d) Please discuss SaskPower's approach to interim and terminal net salvage costs and provide a copy of the relevant accounting policy.

21. Reference: Export Revenues and Electricity Trading

a) Please discuss whether SaskPower's export revenues shown on page 22 of the application include any electricity trading activities and if so, quantify the electricity trading revenues.

b) Please describe the types of export sales (long-term contract, short-term contract, spot market sales) SaskPower makes and provide details of SaskPower's current export transmission rights.

c) Please describe in detail how SaskPower prepares its export revenue forecasts and provide an explanation for the change in export revenues in 2025/26 relative to 2023/24 and 2024/25 actuals.

d) Please provide SaskPower's actual export sales for the last 10 years compared to forecasts from the prior year's business plan (i.e. the last business plan prepared prior to the start of the fiscal year) and discuss the reasons for any variances.

e) SaskPower states at page 22 of the application that electricity capacity in Alberta has increased and lower export prices are expected going forward. Please provide a summary of the proportion of SaskPower's export sales to Alberta compared to other jurisdictions in terms of both volume and revenue for the last 5 actual years.

f) With reference to page 32 and Figure 30 of the Alberta Electric System Operator (AESO) 2024 Annual Market Statistics Report available at: https://www.aeso.ca/assets/Uploads/market-and-system-reporting/Annual-Market-Stats-2024.pdf

   Please discuss the nature and cause of the extended outage that reduced interchange utilization between Saskatchewan and Alberta to zero for 49% of the year.

22. Reference: Other Revenue

a) Please explain how SaskPower forecasts customer contribution revenues in the test years and provide an explanation for the difference in forecasted contributions between 2025/26 and 2026/27.

23. Reference: Other Revenue

a) Please discuss how the CO2 sales revenue forecasts are prepared.

b) Please provide an explanation for the reduction in CO2 sales revenues from 2023-24 ($26 million) to 2024-25 ($19 million).

24. Reference: Other Revenue

a) Please provide a detailed breakout of Miscellaneous Revenue for the five most recent actual years and forecasts for 2025/26 and 2026/27. Please provide an explanation for the decreased revenue in 2025/26 and 2026/27 compared to 2024/25.

25. Reference: Business Plan

a) Please provide a description of SaskPower's annual business planning cycle including inputs required, review and approval processes, and the typical timing of internal and external updates.

26. Reference: Generation expense

a) For each of the last three actuals years, plus forecasts for 2025/26 through 2026/27, please provide the total cost of generation for each fuel source (e.g. coals, natural gas, etc) broken out into:

i. Fuel and purchased power expense
ii. Operations and maintenance expense
iii. Federal carbon charges
iv. Finance charges
v. Depreciation expenses
vi. Taxes
vii. Other

27. Reference: Fuel and Purchased Power (F&PP)

a) Please discuss if there have been any changes to the methods SaskPower uses to prepare its fuel and purchased power forecasts since the response to SRRP Round 1 question 29 from the 2022 and 2023 rate application. If so, please explain any changes.

b) Please provide a table showing the total GWh of generation for each of the last three actual years plus forecasts for 2025-26 and 2026-27 for:

i. SaskPower's own generation
ii. Purchased power within Saskatchewan
iii. Imports from outside Saskatchewan

28. Reference: Fuel and Purchased Power (F&PP)

a) Please identify any actual or forecast energy volumes subject to "Take or Pay" (TOP) obligations under the PPAs (in total) for each of the three most recent actual years and forecasts for 2025-26 and 2026-27.

b) Please discuss whether SPC has been required to pay for unused energy because of TOP provisions and indicate whether any such costs are forecast to be incurred in the three most recent actual years.

29. Reference: Fuel and Purchased Power (F&PP)

a) To the extent possible without requiring the disclosure of confidential information, please provide the most recent actual annual and forecast for the test years average power price for generation owned by SPC and separately, the average purchase price for PPAs by fuel type, and explain any differences in unit costs.

30. Reference: Natural Gas

a) Please describe SaskPower's natural gas procurement processes including details on any firm contracted transmission and/or storage volumes for the three most recent actual years and forecasts for 2025-26 through 2026-27.

31. Reference: Natural Gas

a) Please describe any changes to SaskPower's procedures, Risk Management Policies, and/or Risk Management Manuals related to procurement and pricing of Natural Gas supplies, including Storage and hedging since the last rate application.

32. Reference: Natural Gas

a) Please provide a table showing natural gas purchases within Saskatchewan and outside Saskatchewan including total volumes, average unit costs, and total natural gas expenses for each of the three most recent actual years and forecasts for 2025/26 through 2026/27.

33. Reference: Natural Gas

a) Please provide a schedule showing actual natural gas hedged volumes for the five most recent actual years and currently hedged volumes for 2025/26 through 2026/27. Please summarize the types of financial instruments used each year and indicate the overall annual cost of hedged volumes in aggregate and on a unit basis.

b) Please provide an estimate of the impact of SaskPower's hedging activities on natural gas costs for each of the five most recent actual years. Please also provide a discussion on the net cost or benefit to ratepayers of the hedging program over the past five years.

34. Reference: Natural Gas

a) Please provide a schedule that shows SaskPower's natural gas fuel efficiency ratio (i.e. the kW.h generated per unit of natural gas) for each of the three most recent actual years and forecasts for 2025-26 and 2026-27. Please comment on any material variances between years.

b) Please discuss if the fuel efficiency ratios vary materially across plants and if so, why?

c) Please describe how SaskPower prepares its forecasts of natural gas fuel efficiencies.

35. Reference: Natural Gas

a) Please provide a schedule showing the average cost of transmission and storage per GJ for the three most recent actual years and forecasts for 2025/26 through 2026/27.

36. Reference: Coal

a) Please provide the average heat values for coal generation for each of the past three actual years and forecasts for 2025-26 and 2026-27.

b) With reference to the statement on page 5 of the application that SaskPower is executing a program to life-extend its coal-fired generation facilities for 25 years, please:

   i. Provide a detailed description of the Coal Fleet Repowering Initiative including current estimated timelines to refurbish each of the units and associated costs per unit.

   ii. Provide copies of any and all financial and economic analyses conducted by SaskPower or the provincial government to confirm extending the life of coal facilities would be the lowest cost generation option over the long term compared to other potential generation sources.

iii. Please discuss the implications for SaskPower's existing coal supply contracts and provide a discussion of when its current contracts expire and timelines for future coal supply contract negotiations.

iv. Please discuss whether SaskPower will be able to make use of its existing carbon capture and storage facilities when the repowering initiative is complete and whether or not SaskPower has plans for additional carbon capture and storage facilities.

37. Reference: Hydro

a) Please provide an update on the status of potential future hydro projects, including upgrades to existing facilities and the Tazi Twé project, and discuss whether SaskPower views additional hydro capacity may be feasible in the future.

38. Reference: Hydro

a) Please provide a schedule showing the actual and forecasted water rental rates for the three most recent years of actuals and forecasts for 2025/26 through 2026/27.

39. Reference: Hydro

a) Please describe how SaskPower forecasts hydro generation availability including any historical data inputs.

b) Please provide any updates on the expected flow conditions for 2026-27 based on recent snowfall or other conditions since the business plan supporting the rate application was prepared.

c) Please discuss whether SaskPower has prepared an analysis of the potential effects of climate change on future hydro generation and if so, provide a summary of the analysis.

40. Reference: Wind

a) Please provide a schedule showing actual and forecasted monthly wind generation in GWh and wind capacity factors for wind facilities for the last three actual years and forecasts for 2025-26 and 2026-27.

41. Reference: Purchase Power Agreements

a) Have SaskPower's requirements for IPPs related to decommissioning, site remediation and site restoration changed since the response to first round SRRP-Q44 from the previous GRA? If so, please provide an update to that response.

b) With reference to the solar RFP being undertaken by the First Nations Power Authority described on page 31 of the application, please describe SaskPower's arrangements with the First Nations Power Authority for the supply of power and provide any updates on timing for results of the proposal process.

42. Reference: Imports

a) Please provide a schedule showing actual and forecasted import volumes and average prices separately for firm import contracts and spot market or short-term contracts for each of the last four actual years and forecasts for 2025-26 and 2026-27.

b) Please discuss any current plans SaskPower has to increase import capabilities from other jurisdictions.

43. Reference: Solar and Other

a) Please provide an explanation for the forecast increase in other fuel and purchased power expense and volumes for 2025-26 and 2026-27.

b) With reference to the discussion on page 8 of SaskPower's 2024-25 annual report, please discuss the benefits and costs of the utility scale 20 MW battery project. Does SaskPower anticipate deploying more utility scale batteries?

44. Reference: Operating, Maintenance and Administration (OM&A)

a) Please provide a schedule that breaks out actual and forecast total OM&A costs for the three most recent actual fiscal years and forecasts for the test years in a format similar to the response to SRRP Pre-Ask 7 from the 2022 and 2023 Rate Application.

b) Please provide a comparison of the 2021/22, 2022/23, and 2023/24 forecasts from the last Rate Application and actual OM&A spending for 2021/22, 2022/23, and 2023/24 and current forecasts for 2025/26 and 2026/27. Please discuss the reasons for any material variances.

c) Please provide an explanation for year over year changes in actual and forecast salaries and wage expenses noting changes driven by:

i. staff or employee complement
ii. average salary costs per position
iii. overtime costs
iv. vacancy rates
v. corporate credits
vi. labour credits

d) Please discuss any efficiency initiatives undertaken since the previous rate application or forecast for the test years to reduce OM&A and demonstrate how they are quantified and reflected in the current rate application.

45. Reference: Operating, Maintenance and Administration (OM&A)

a) Please provide the actual vacancy rates for the three most recent years and forecasts for 2025/26 through 2026/27.

b) Please discuss how SaskPower forecasts vacancy rates for business planning purposes.

46. Reference: Operating, Maintenance and Administration (OM&A)

a) Please provide an update to the response to Round 1 SRRP Q47 from the 2022 and 2023 rate application adding any actual year results available since 2020/21.

b) Please provide an explanation for any material variances between forecasts and actuals in the information provided in the response to part (a).

47. Reference: Operating, Maintenance and Administration (OM&A)

a) Please provide a breakout of SaskPower's OM&A spending by business unit for each of the five most recent years of actuals and forecasts for 2025/26 through 2026/27.

48. Reference: Operating, Maintenance and Administration (OM&A)

a) Please provide the actual overhaul spending for the three most recent years and forecasts for 2025-26 through 2026-27.

49. Reference: Operating, Maintenance and Administration (OM&A)

a) Please indicate when the current collective agreements are set to expire and provide an update on the status of any negotiations for future collective agreements.

b) With reference to the response to SRRP Q51 (b) from the 2022 and 2023 rate application please provide an updated breakdown of FTEs between employees covered by collective agreements and those excluded from collective agreements for all actual years available.

50. Reference: Operating, Maintenance and Administration (OM&A)

a) Please provide a schedule that breaks out spending on advertising, communications, marketing, donations and sponsorships for the three most recent actual years and forecasts for the test years.

b) Please provide the dollar values and recipients of SaskPower's five largest donations or sponsorships for each of the three most recent actual years.

c) Please discuss how SaskPower selects the recipients of its donations and sponsorships.

d) Please confirm donations and sponsorships are included in the total OM&A figures in the table on page 26 of the application.

51. Reference: Operating, Maintenance and Administration (OM&A)

a) Please summarize SaskPower's overtime policies and describe how SaskPower forecasts overtime.

b) Please summarize SaskPower's standby pay policies and describe how SaskPower forecasts standby pay requirements for the test years.

52. Reference: Operating, Maintenance and Administration (OM&A)

a) Does SaskPower have bonus or at-risk pay incentive structures for any employees? If so, please provide a summary of any such programs.

53. Reference: Operating, Maintenance and Administration (OM&A)

a) Please provide SaskPower's calculations and underlying data for its OM&A per customer account and OM&A per residential account for all years presented in the 2026–27 GRA. This request includes the data used to produce the "OM&A per residential account" figure shown on page 26 of the 2026–27 GRA.

b) Please explain any differences between these metrics and the "OM&A per customer account" values reported in the 2024–25 Annual Report.

54. Reference: Nuclear

a) With reference to the statement on page 5 of the application that "SaskPower is undertaking planning and project development work required to deploy nuclear power starting in the mid to late 2030s." Please provide a schedule showing all costs related to nuclear planning and development work included in the last 3 actual years and forecast for the test years.

b) Please clarify confirm if the mid to late 2030s timeline is the anticipated timeline for nuclear power to begin to be delivered to SaskPower's grid. If not, please explain. If yes, please indicate when SaskPower anticipates it would begin the regulatory approvals process.

c) Please provide copies of any publicly available collaboration agreements or funding agreements related to the nuclear planning and project development work.

55. Reference: OM&A – Distribution system reliability

a) With reference to page 26 of the application, please provide a schedule showing the number of positions and costs related to additional resources to modernize and maintain SaskPower's distribution grid for each of the last three actual years and forecasts for 2025/26 through 2026/27.

56. Reference: OM&A – Vegetation management

a) Please provide a schedule showing the costs related to vegetation management included in total OM&A for each of the last three actual years and forecasts for 2025/26 through 2026/27.

b) Please describe SaskPower's vegetation management processes e.g. mechanical clearing, chemical/herbicide, other methods and explain why SaskPower has selected that method or methods.

57. Reference: Information Technology

a) To assist the Panel in understanding changes in IT costs please provide, for each of the last three actuals years plus forecasts for 2025/26 through 2026/27, SaskPower's total IT related costs broken out into:

   i. Operations and maintenance expenses
   ii. Finance expenses
   iii. Depreciation expenses
   iv. Return on equity
   v. Other

b) Please describe SaskPower's approach to cybersecurity, including how SaskPower develops and monitors its cybersecurity policies and procedures and any recent updates to those policies and procedures.

c) Has SaskPower had any cybersecurity incidents that resulted in material business interruptions or insurance claims? If so, please provide a description that can be made public of any such incidents.

58. Reference: Tax Expense

a) Please provide a table showing the detailed calculation of SaskPower's corporate capital tax obligation for the three most recent actual years and forecasts for the test years.

59. Reference: Other Expenses

a) Please provide a break-out of SaskPower's Other expense category including Asset Disposals, Asset Retirements, Foreign exchange (if any), and Environmental Expenses for each of the five most recent actual years and forecasts for 2025/26 through 2026/27.

60. Reference: Debt and Equity

a) Please provide a schedule showing SaskPower's actual and forecast capital structure (long-term debt; short-term debt, equity, other sources of financing) for the three most recent years of actuals and forecasts for the test years.

b) Please provide the calculation of the operating return on equity percentage for each the three most recent years of actuals and forecasts for the test years showing;

   i. the calculation of the operating income
   ii. the calculation of the equity component of SaskPower's total capital structure and the equity component of ratebase.

c) Please confirm the current borrowing limit for SaskPower pursuant to the Power Corporation Act.

d) Please provide SaskPower's actual unused credit capacity at the most recent actual year and forecasts for 2025-26 and 2026-27.

e) Has SaskPower received any equity advances or repayments since the time of the last rate application? If so, please quantify and describe the circumstances associated with the equity advances or repayments.

f) Please provide a table comparing SaskPower's debt ratio with other peer Canadian utilities for the most recent actual years available.

61. Reference: Productivity and Efficiency

a) Please discuss how SaskPower budgets for and tracks productivity and efficiency improvements in its operating budgets.

b) Please provide any quantifiable information SaskPower maintains on tracking the long-term savings of productivity and efficiency programs.

62. Reference: Safety

a) Please provide the five most recent years of actual lost-time injury frequency rates, lost-time injury severity rates, and recordable injury frequency rates for SaskPower and peer utilities.

b) Please provide an overview of how SaskPower's workplace safety programs and how SaskPower responds to changes in safety rates.

63. Reference: Wildfire Risk

a) Has SaskPower prepared a wildfire risk assessment and management plan? If so, please provide a copy. If not, please discuss how SaskPower manages its wildfire risk.

b) Please provide a table showing SaskPower's spending for each of the last five actual years and forecasts for 2025-26 and 2026-27 on:

   i. wildfire response (i.e. responding to specific wildfire events)
   ii. wildfire risk mitigation plans or programs

c) Please provide an estimate of the amount of wildfire response spending in part (b) that was covered by insurance.

d) What proportion of SaskPower's existing transmission infrastructure is wood compared to steel or other materials.

e) Please discuss how wildfire risk has influenced how SaskPower plans its transmission capital program.

64. Reference: Capital Program

a) Please describe any changes to SaskPower's capital planning process since the time of the last rate application in particular with respect to:

   i. how project scopes and budgets are developed;
   ii. the approval process for SaskPower's capital plan;
   iii. how SaskPower paces and prioritizes its capital plans (for example, does SaskPower develop a high-level capital spending envelope and then prioritize projects within that envelope); and
   iv. how SaskPower manages and monitors the delivery of its capital projects including project reporting, variance analysis, and quality assurance in the delivery of each capital project.

65. Reference: Capital Program

a) Please expand the capital spending table provided on page 30 of the application to include the most recent five years of actual spending.

66. Reference: Capital Program

a) For each capital project or program with final costs in excess of $10 million for each of the last three actual years please provide:

i. The justification for the project (e.g. capacity or system growth requirements; infrastructure renewal; operating efficiencies/savings)
ii. the original budget allocation
iii. the final actual project direct costs
iv. capitalized interest, overheads, and other charges;
v. an explanation for any variances of more than 10% from the original budget.

67. Reference: Capital Program

a) With reference to the rural rebuild and improvement program, please discuss how SaskPower identifies and prioritizes the lines to be replaced.

68. Reference: Capital Program

a) With respect to the smart meter deployment described on page 9 of SaskPower's 2024-25 annual report, please provide an update on how many smart meters have been installed and when SaskPower expects the roll-out will be complete.

b) Does SaskPower have any plans to develop the back-end systems that would be necessary to support demand response or time-of-use rates for residential and small commercial customers? Please discuss.

69. Reference: Customer connects

a) Please provide SaskPower's customer connect spending by customer class for each of the last three actual years and forecasts for 2025-26 and 2026-27.

b) Please describe any updates or changes to SaskPower's customer connect policies since the time of the 2022 and 2023 rate application.

70. Reference: Load Forecasts

a) Please discuss any changes to assumptions, methodology, or explanatory variables used for the load forecasts and customer count forecasts for each major customer class since the previous rate application, including any changes affecting input data.

b) Please discuss any alternative assumptions, methods, and explanatory variables that were tested by SaskPower for the load forecasts or customer count forecasts and why these were not chosen for the final forecasts.

71. Reference: Load Forecasts

a) For each of the ten most recent actual years, please provide a schedule showing the actual sales for each major customer group and the sales forecast from the load forecast immediately preceding the actual year. Please also include forecast and actual line losses and station service. Comment on any material variances between actuals and forecasts.

b) Please provide a table showing 10 years of electricity sales and customer account forecasts from the load forecasts used to support each of the last three rate applications. The 10 years of forecasted data should start from the first test year of each Rate Application (t+10).

c) Please comment on the steps SaskPower takes to verify large-scale industrial and commercial customer load forecasts including for potential new customers.

d) With reference to the media reports of a planned data centre near Regina (see: https://www.cbc.ca/news/canada/saskatchewan/bell-ai-data-centre-regina-9.7083484) please discuss:

   i. Is SaskPower aware of the approximate capacity and energy that will be required by the data centre?
   ii. Does SaskPower have sufficient generation and transmission capacity available or would this project require new infrastructure?

iii. Is SaskPower aware of whether or not there were any federal, provincial or municipal government incentives offered to the developer?

72. Reference: Load Forecasts

a) Please provide the forecasted and top three actual system winter and summer peaks for each of the five most recent actual years.

b) Please comment on any material variances between actual and forecast peaks for the most recent five years as well as how any changes in methodology to the current system peak demand forecast will improve forecast accuracy.

c) Please provide the generation capacity by fuel type used to meet the top actual system winter and summer peaks.

d) Please elaborate on the statement on page 10 of the application that "Most of the increase is related to Power customer class sales, especially in the mining, pipeline, and refinery sectors" and quantify the changes in peak demand by customer type for each of the last three years and forecasts for 2025/26 through 2026/27.

73. Reference: Energy Efficiency

a) Has SaskPower completed a more recent Conservation Potential Review than the 2017 Navigant report? If so, please provide a copy. If not, please discuss if and when SaskPower intends to commission an updated study.

b) With reference to the energy efficiency programs summarized in section 2.1 of the application, please provide the actual costs associated with these programs for the three most recent actual years and forecasts for 2025/26 through 2026/27 by rate class and the estimated energy and capacity savings associated with each program.

c) Please provide summary details of any other energy efficiency, demand side management, or conservation programs currently administered by SaskPower beyond those summarized in section 2.1 of the application.

74. Reference: Capacity Reserve Programs

a) Please comment on any changes that have occurred to the Spinning Capacity Reserve and Planned Operating Capacity Reserve programs since the last rate application.

b) Please provide a summary of subscriptions to the capacity reserve programs, including the total number of customers and the total amount of capacity subscribed to each rate option for each of the last three years.

75. Reference: Net Metering Program

a) Please discuss if SaskPower has made any changes to the Net Metering program, including terms and conditions and pricing, since the time of the last rate application. If so, please provide a summary of such changes.

b) Please provide a summary of subscriptions to the net metering program including the total number of customers subscribed, the total installed capacity, and the total generation delivered from customers to SaskPower under the program for each of the last three years.

c) Has SaskPower undertaken any engagement with net metering customers since the time of the last rate application? If so, please provide the results of that engagement.

76. Reference: Cost of Service Study

a) Please provide a copy or weblink to the most recent external review of SaskPower's cost of service study methods.

b) Please provide a table showing:

   i. The recommended changes from the consultant
   ii. Whether SaskPower adopted the recommended changes and if not an explanation for why not.

c) Please discuss if there have been any other changes made to the cost of service study methodology since the last external review and if so, please itemize them and provide a discussion of the rationale for the change.

d) Please discuss when SaskPower anticipates its next external review of its cost of service methodology will take place.

77. Reference: Proposed Rates Revenue to Revenue Requirement Ratios

a) Please provide the revenues and revenue requirement breakdowns by class in dollars supporting the calculation of the 2025/26 revenue to revenue requirement ratios illustrated in the first table on page 35 of the application and the 2026/27 revenue requirement ratios illustrated in the first table on page 36 of the application.

b) Please provide a table showing the 2025/26 and 2026/27 percentage rate increases by class that would be required to have all customer classes achieve revenue to revenue requirement ratios of between 0.98 and 1.02 by 2026/27.

78. Reference: Proposed Rates

a) SaskPower states on page 33 and 34 of the 2026 Fiscal Test Embedded Cost of Service Results that "..due to the transition to a Conventional Rate Design and the number of years since SaskPower's last rate rebalancing rate application, to avoid rate shock to certain rate classes, more discretion in the ratios had to be taken in this application." Please explain what SaskPower means by a "Conventional Rate Design" – does this mean equal percentage increases to all rate components and customer classes?

b) Did SaskPower consider alternative rate designs for the current application? If so please provide a summary of the alternatives considered.

c) Please discuss when SaskPower anticipates it will complete the phase-out of the Bary correction.

d) Please provide a schedule that compares, for each rate class:

   i. The 2026/27 class revenue requirement classified to each of energy, demand, and customer.
   ii. The forecast 2026/27 total class revenue generated by each of energy charges, demand charges, and customer charges.

e) For each customer class in each test year, please provide a table that compares the "ideal rates" calculated by the cost of service study for each of demand, energy, and customer with SaskPower's proposed energy, demand, and customer charges. Please comment on any material differences between proposed rates and ideal rates.

79. Reference: Proposed Rates

a) Please provide a summary of municipal surcharges, including both the percentage of the surcharge and the total dollars collected for the most recent actual year available.

80. Reference: System Operations

a) Please describe SaskPower's dispatch policies or rules for use of the various fuel sources to meet capacity and energy requirements. Please highlight any changes to these dispatch policies or rules since the last rate application.

b) Please discuss how the coal refurbishment program will affect SaskPower's system operation dispatch policies.

c) Does SaskPower anticipate the coal re-powering program will have any effect on the average generation efficiency of its natural gas generation facilities?

81. Reference: Reliability

a) Please provide a table summarizing transmission SAIDI, transmission SAIFI, distribution SAIDI, distribution SAIFI, and distribution CAIDI for the most recent five years of actuals available for each of:

   i. SaskPower
   ii. SaskPower Targets
   iii. Canadian Utility Averages

b) Please discuss any factors contributing to SaskPower's performance relative to the average of the other utilities such as reporting framework (e.g., including or excluding Major Event Days, different requirements for planned outages, etc.).

c) Please discuss how SaskPower considers its reliability indicator performance when developing its capital plan. Does SaskPower prioritize capital spending to address particular areas or types of outages observed to impact reliability performance?

d) For each of transmission and distribution, please provide a breakdown of the causes of outages by type for both outage frequency and duration for each of the last three actual years available, similar to the format of the response to SRRP Q97 from the first round interrogatories in the 2022 and 2023 Rate Application review.

e) Please provide SaskPower's actual system average generation equivalent availability factor (EAF) for the most recent 5 actual years available and provide explanations for any changes over time.

f) NERC's Long Term Reliability Assessment (see: https://prod.nerc.com/globalassets/our%2Dwork/assessments/nerc_ltra_2025.pdf) indicated SaskPower had an elevated risk profile. Can you please outline what steps SaskPower has taken or will be taking to reduced this elevated risk profile.

82. Reference: Resource Planning

a) With reference to the response to the Panel's first recommendation from the 2022-2023 rate application where SaskPower states "SaskPower has completed extensive work on a public version of the Integrated Resource Plan. Over 60,000 people engaged with SaskPower through the process to date. SaskPower has updated the SRRP, and updates are publicly available on our website, saskpower.com. The release of the Long-term Supply Plan has been postponed due to the changing generation supply mix." Please:

   i. Provide a summary of the results of the public engagement on the Integrated Resource Plan.
   ii. Please provide an update on when SaskPower believes it will be in a position to provide a public version of the Long-term Supply Plan.

b) Please itemize the planning criteria used by SaskPower in developing its Resource Plans such as firm energy and capacity requirements. Please include any policy objectives such as reducing greenhouse gas emissions or installing a particular capacity of renewable generation.

c) Please discuss whether SaskPower has any current GHG emissions reductions targets. Please provide a chart that shows SaskPower's actual and forecast GHG emissions by year from 2005 through 2030.

d) Please provide a table that shows the contribution to SaskPower's GHG emissions by generation type for each year from 2005 through 2030.

e) Please provide an update to the response to SRRP first round Q102 from the 2022 and 2023 rate application for as many forecast years as SaskPower has available and can make public.

f) Please provide a table that compares the generation mix available to meet the winter peak and the generation mix available to meet the summer peak for planning purposes and describe the reasons for any differences in the seasonality of the planning capacity by generation type.

83. Reference: Forecast Sales Revenues

a) Please provide a proof of revenue schedule for each of the test years showing:

i) The forecast billing determinants (e.g. number of customers, billed demand, energy), for each rate class;

ii) SaskPower's existing rates and proposed rates for each rate class

iii) Forecast revenues at existing rates and at proposed rates for each rate class.

SaskPower
Powering our future®

2026 AND 2027 RATE APPLICATION
SRRP INTERROGATORIES

SRRP Q1 Reference: Application

a) Please provide the date of the business plan that forms the basis of the application and identify the date of any updates to that business plan included in the application.

b) Please summarize any changes to SaskPower's chart of accounts or accounting treatments since the last rate application and advise of any resulting issues in comparability of figures between the last rate application and the current rate application.

c) Please describe the changes in accounting treatment of information technology costs discussed on page 26 of the application and identify the impact on operations and maintenance costs and capital costs in the test years.

Response:

a) Saskatchewan sales revenue and fuel and purchased power expenses were based on the Fiscal 2026 Q1 Load Forecast, which was finalized in April 2025. All other revenue and expense categories were based on the 2026-27 Business Plan, finalized in December 2025.

b) There have been no changes to SaskPower's chart of accounts or accounting treatments since the last rate application that would result in issues in comparability.

c) Effective for fiscal years beginning January 1, 2020, IFRS revised the definition of an asset for accounting purposes. To comply with the new conceptual framework for financial reporting, SaskPower along with many other companies began expensing all costs related to the design and implementation of cloud computing solutions (i.e. software as a service – SaaS). This is due to the fact that while these SaaS arrangements provide the right and ability to access and use the software for its operations as SaskPower does not own or control the rights to the software it does not meet the requirements for capitalization.

The following table provides the actual amount of SaaS or cloud computing solutions included in operating, maintenance and administration expenses for 2022-23 through 2024-25, and the forecasted amounts in 2025-26 and 2026-27. Prior to the change in accounting treatment, all or a portion of these costs could have potentially been capitalized.

Software as a Service (SaaS)

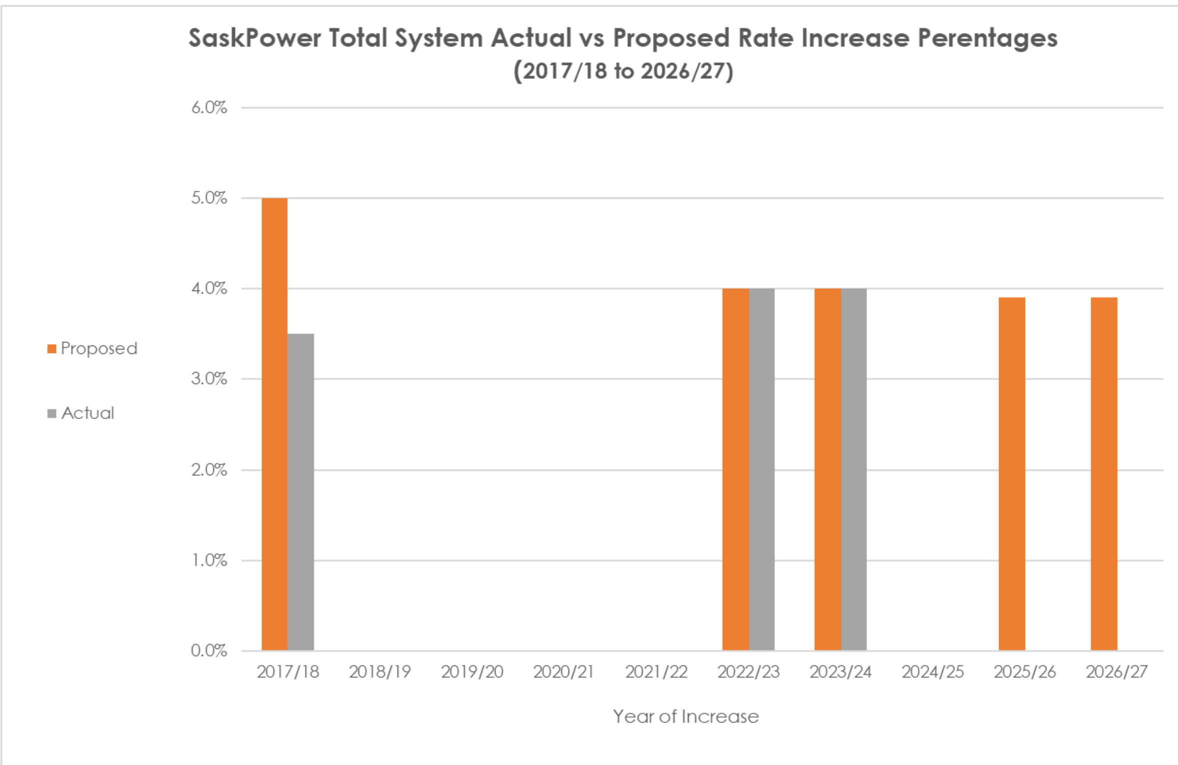
(in millions)	Actual **2022-23**	Actual **2023-24**	Actual **2024-25**	Forecast **2025-26**	Forecast **2026-27**
Operating, maintenance and administration	$ 13	$ 14	$ 15	$ 15	$ 14

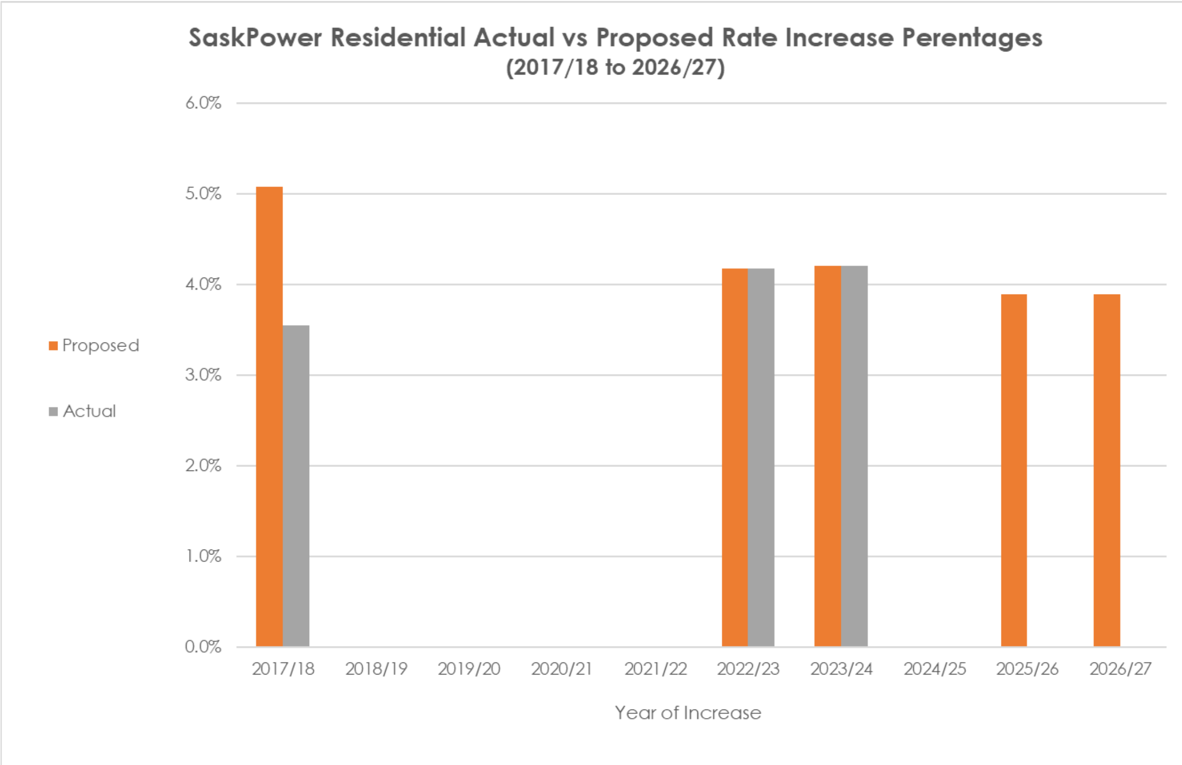
SRRP Q2 Reference: Application

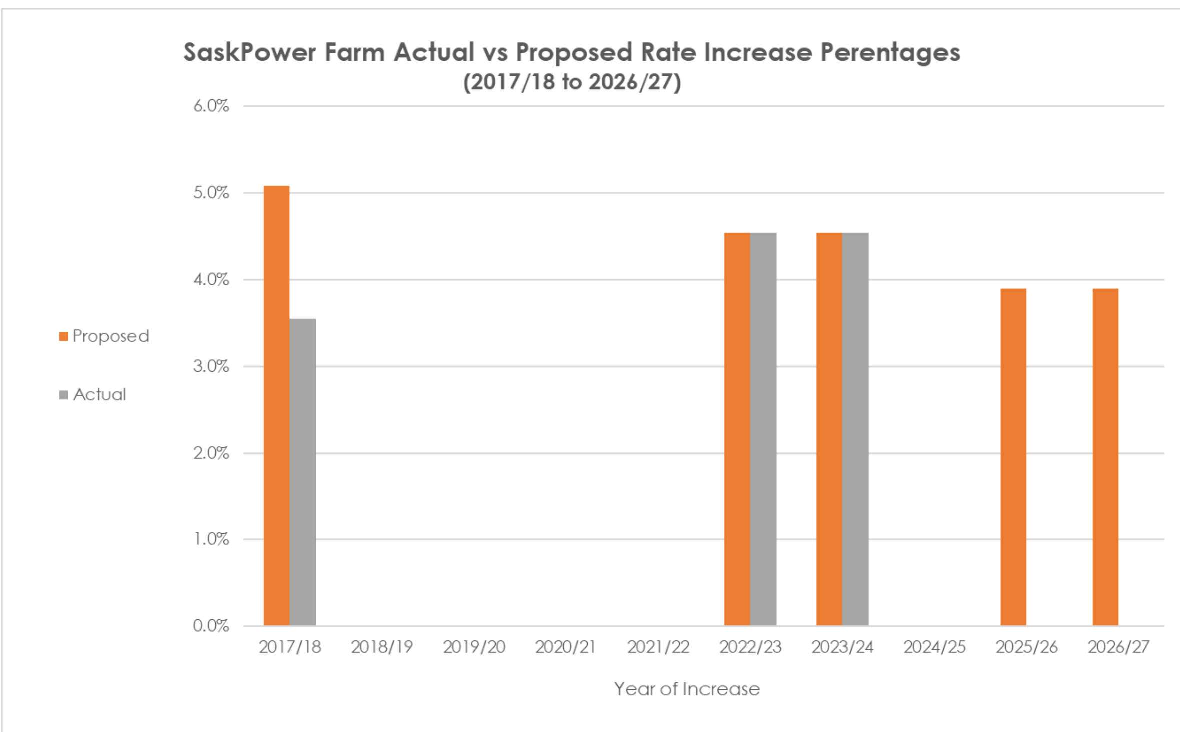
a) Please provide a graph which illustrates the actual and proposed percentage increases for each major customer group from 2017/18 through 2026/27 similar to the response to SRRP-Q2 from the first round interrogatories from the 2022 and 2023 Rate Application.

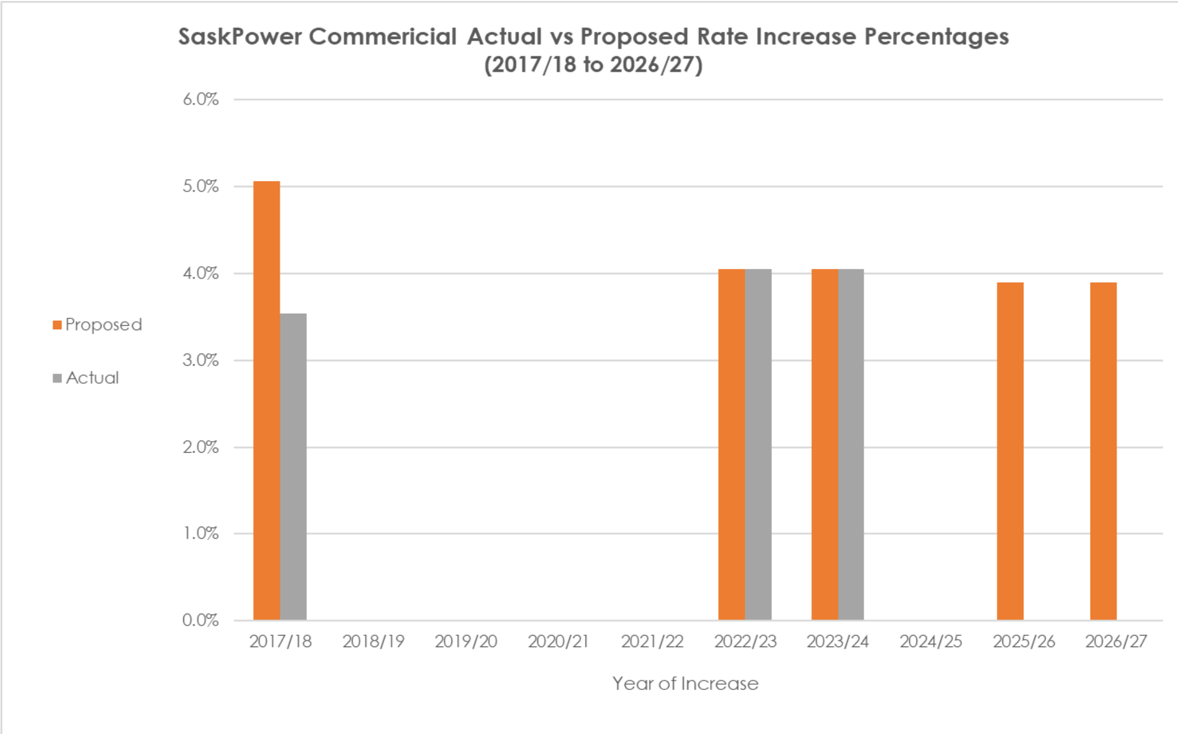
Response:

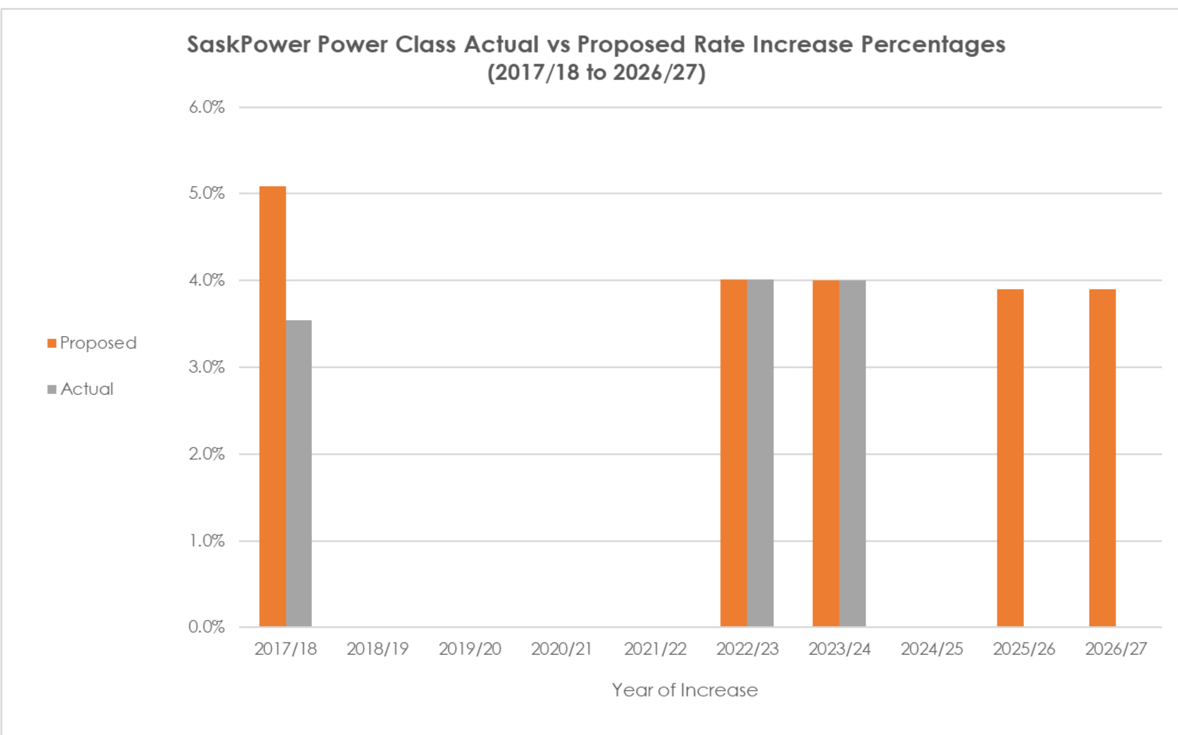
Please see the tables below:

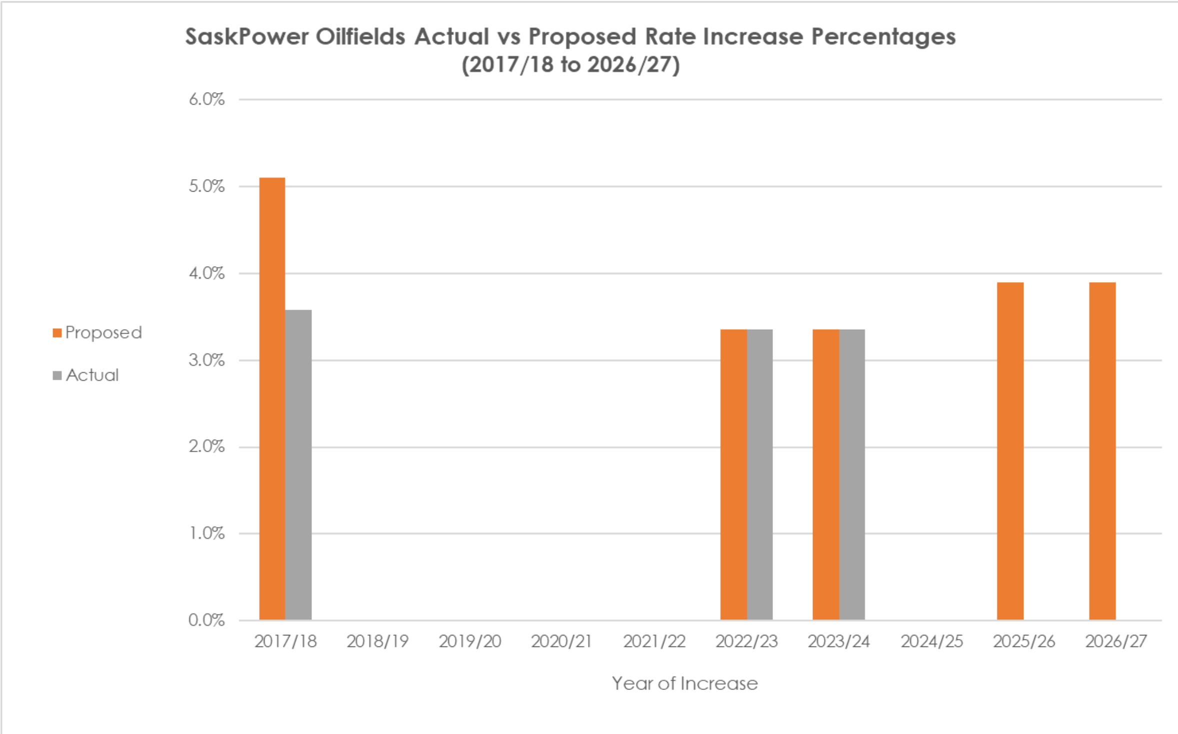


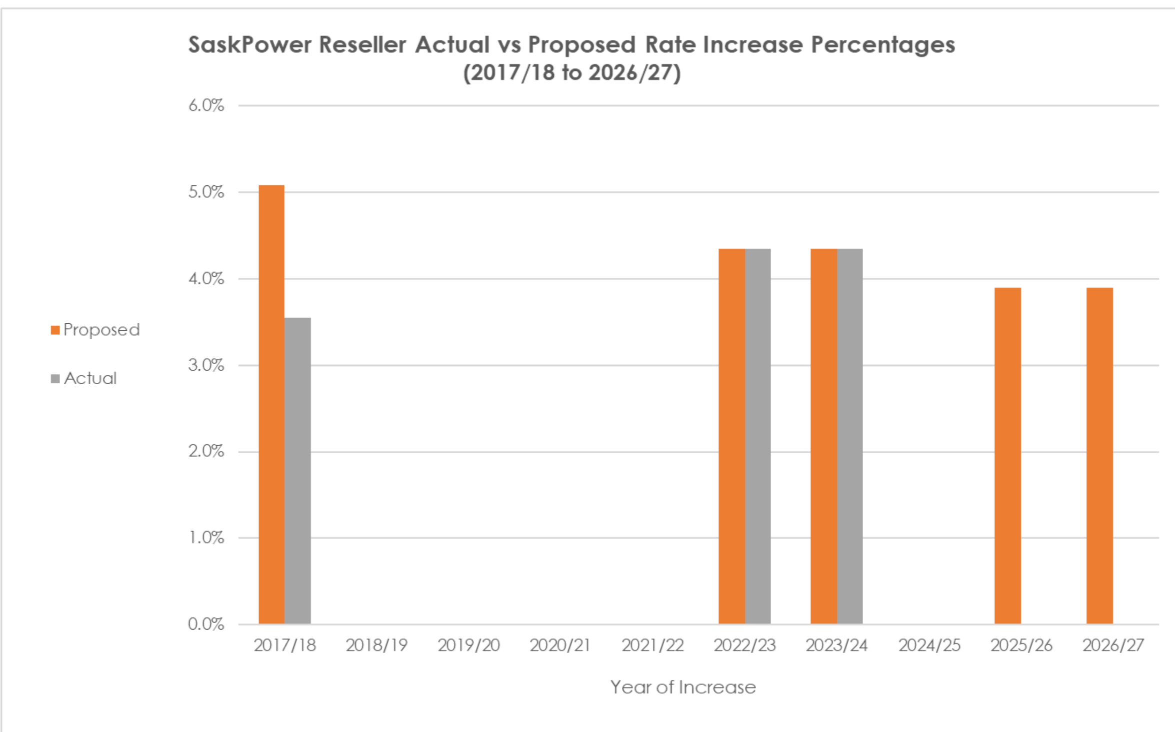

SaskPower Residential Actual vs Proposed Rate Increase Perentages
(2017/18 to 2026/27)
6.0%
5.0%
4.0%
3.0%
2.0%
1.0%
0.0%
Proposed
Actual
2017/18
2018/19
2019/20
2020/21
2021/22
2022/23
2023/24
2024/25
2025/26
2026/27
Year of Increase


SaskPower Farm Actual vs Proposed Rate Increase Perentages
(2017/18 to 2026/27)
6.0%
5.0%
4.0%
3.0%
2.0%
1.0%
0.0%
Proposed
Actual
2017/18
2018/19
2019/20
2020/21
2021/22
2022/23
2023/24
2024/25
2025/26
2026/27
Year of Increase


SaskPower Commericial Actual vs Proposed Rate Increase Percentages
(2017/18 to 2026/27)
Proposed
Actual
6.0%
5.0%
4.0%
3.0%
2.0%
1.0%
0.0%
2017/18
2018/19
2019/20
2020/21
2021/22
2022/23
2023/24
2024/25
2025/26
2026/27
Year of Increase


SaskPower Power Class Actual vs Proposed Rate Increase Percentages
(2017/18 to 2026/27)
Proposed
Actual
6.0%
5.0%
4.0%
3.0%
2.0%
1.0%
0.0%
2017/18
2018/19
2019/20
2020/21
2021/22
2022/23
2023/24
2024/25
2025/26
2026/27
Year of Increase


SaskPower Oilfields Actual vs Proposed Rate Increase Percentages
(2017/18 to 2026/27)
6.0%
5.0%
4.0%
3.0%
2.0%
1.0%
0.0%
Proposed
Actual
2017/18
2018/19
2019/20
2020/21
2021/22
2022/23
2023/24
2024/25
2025/26
2026/27
Year of Increase


SaskPower Reseller Actual vs Proposed Rate Increase Percentages
(2017/18 to 2026/27)
6.0%
5.0%
4.0%
3.0%
2.0%
1.0%
0.0%
Proposed
Actual
2017/18
2018/19
2019/20
2020/21
2021/22
2022/23
2023/24
2024/25
2025/26
2026/27
Year of Increase

SRRP Q3 Reference: Application

a) Please provide a schedule showing SaskPower's total domestic electricity sales revenue; operating income; return on equity, debt to equity ratio, revenue lift and percentage rate increase for 2025/26 and 2026/27 assuming each of the following potential rate scenarios:

i. Confirmation of the 3.9% average rate increases effective February 1, 2026 and February 1, 2027 as applied for;

ii. Confirmation of 2% average rate increases effective February 1, 2026 and February 1, 2027;

iii. No rate increases in 2025/26 or 2026/27;

iv. Equal percentage rate increases effective February 1, 2026 and February 1, 2027 that achieve the long-term target ROE of 8.5% in the 2026/27 fiscal year.

v. Equal percentage rate increases effective February 1, 2026 and February 1, 2027 that achieve an ROE of 6.0% in the 2026/27 fiscal year.

vi. Equal percentage rate increases effective February 1st each year for five years that achieve the long-term target ROE of 8.5% by the final year.

vii. Equal percentage rate increases effective February 1, 2026 and February 1, 2027 that achieve a 75% debt ratio by the end of 2026/27.

viii. Equal percentage rate increases effective February 1st 2026 and each subsequent year for five years that achieve a 75% debt ratio by the final year.

b) Please discuss why SaskPower elected not to file a three year rate application given that the application was filed more than 9 months into the first test year.

c) Please provide estimated debt ratios, ROE percentage and operating income in 2027/28 assuming:

i. No further rate increases in 2027/28.

ii. An additional 3.9% rate increase effective February 1, 2028.

Response:

a) The following tables provide estimated Saskatchewan electricity sales, net income, return on equity, per cent debt ratio, revenue lift and rate increases based on the assumptions provided in questions a(i) through a(viii). Scenarios have only been provided for the years being reviewed in this rate application (2025-26 and 2026-27).

(in millions)	i. 2025-26	i. 2026-27	ii. 2025-26	ii. 2026-27	iii. 2025-26	iii. 2026-27	iv. 2025-26	iv. 2026-27
Saskatchewan sales (incl. rate increase)	$ 2,922.1	$ 3,106.5	$ 2,912.9	$ 3,040.1	$ 2,903.2	$ 2,970.6	$ 2,944.7	$ 3,271.6
Net income	$ (146.7)	$ 78.9	$ (155.9)	$ 12.6	$ (165.6)	$ (58.5)	$ (124.1)	$ 245.1
Return on equity	(5.2%)	2.8%	(5.5%)	0.5%	(5.9%)	(2.2%)	(4.4%)	8.5%
Per cent debt ratio	79.2%	80.1%	79.2%	80.6%	79.3%	81.2%	79.0%	78.9%
Cumulative revenue lift	$ 18.9	$ 135.9	$ 9.7	$ 69.5	$ -	$ -	$ 41.5	$ 301.0
Rate increase	3.90%	3.90%	2.00%	2.00%	0.00%	0.00%	8.58%	8.58%

(in millions)	v. 2025-26	v. 2026-27	vi. 2025-26	vi. 2026-27
Saskatchewan sales (incl. rate increase)	$ 2,934.6	$ 3,197.3	$2,930.4	$3,166.9
Net income	$ (134.3)	$ 171.0	$ (138.4)	$ 140.3
Return on equity	(4.7%)	6.0%	(4.9%)	4.9%
Per cent debt ratio	79.1%	79.4%	79.1%	79.6%
Current year revenue lift	$ 31.4	$ 195.3	$ 27.2	$ 169.1
Rate increase	6.48%	6.48%	5.62%	5.62%

(in millions)	vii. 2025-26	vii. 2026-27	viii. 2025-26	viii. 2026-27
Saskatchewan sales (incl. rate increase)	$ 3,018.4	$ 3,823.5	$2,942.2	$3,252.8
Net income	$ (50.5)	$ 803.1	$ (126.7)	$ 226.5
Return on equity	(1.8%)	24.9%	(4.5%)	7.8%
Per cent debt ratio	78.4%	75.0%	79.0%	79.0%
Current year revenue lift	$ 115.2	$ 737.7	$ 39.0	$ 243.2
Rate increase	23.80%	23.80%	8.05%	8.05%

b) Rate increases are a last resort option at SaskPower. As many factors that are outside of SaskPower's control can significantly impact future financial results, SaskPower elected to not file a three-year application. Instead, we will revisit the need for a 2028 rate increase at a later date.

c) The 2027/28 period is outside of the scope of the current rate application.

SRRP Q4 Reference: Application

a) Please provide a continuity schedule of Plant in Service and Total Property, Plant and Equipment by function (generation, transmission, distribution, general) for the three most recent actual years and forecasts for 2025/26 and 2026/27 similar to the response to SRRP-Q5 from the first round interrogatories from the 2022 and 2023 Rate Application.

Response:

Please see the table below:

SaskPower Plant in Service by Function
(in $ Millions)

	Actual			Forecast	
PLANT IN SERVICE	**2021-22**	**2022-23**	**2023-24**	**2025-26**	**2026-27**
Power Production					
Power Production - SaskPower Units	$7,768.7	$7,842.6	$7,907.0	$9,631.8	$10,062.8
Power Production - PPA	$1,017.1	$1,017.1	$1,017.1	$1,218.4	$1,218.4
Coal Reserves	$71.6	$71.7	$72.4	$75.0	$77.8
Shand Greenhouse	$5.8	$5.8	$6.0	$6.0	$6.0
Total	**$8,863.2**	**$8,937.1**	**$9,002.5**	**$10,931.2**	**$11,365.0**
Transmission					
Grid Lines	$1,366.4	$1,390.4	$1,485.8	$1,622.3	$1,794.0
Area Lines	$774.0	$822.7	$890.6	$972.5	$1,075.4
230kv Lines	$298.7	$302.5	$316.6	$345.7	$382.3
138kv Lines	$226.8	$235.3	$240.3	$262.4	$290.2
72kv Bus	$43.0	$45.9	$48.0	$52.4	$57.9
Common & Spares	$282.5	$287.4	$309.2	$337.7	$373.4
Total	**$2,991.4**	**$3,084.3**	**$3,290.6**	**$3,592.9**	**$3,973.2**
Distribution					
Mobile and Area Substations	$436.7	$448.7	$460.6	$509.5	$543.4
25kV Lines (Urban & Rural Combined)	$1,354.0	$1,428.1	$1,492.4	$1,650.8	$1,760.7
14.4kV Distribution Urban	$486.5	$502.2	$522.5	$584.4	$626.7
14.4kV Distribution Rural	$908.6	$940.3	$980.5	$1,084.6	$1,156.8
Distribution Transformers	$578.0	$604.4	$639.2	$707.0	$754.1
Urban Residential Services	$187.2	$198.3	$204.4	$228.6	$245.1
Rural Residential Services	$92.3	$100.4	$109.0	$120.6	$128.6
Urban Commercial Services	$234.0	$245.7	$260.6	$291.5	$312.6
Rural Commercial Services	$134.8	$140.9	$148.2	$163.9	$174.8
Farm Services	$43.7	$61.6	$90.3	$94.9	$51.5
Oilfield Services	$187.1	$195.4	$202.3	$223.7	$238.6
Streetlights	$122.9	$131.4	$140.6	$150.4	$160.8
Meters	$110.2	$110.4	$117.4	$132.5	$155.1
Instrument Transformers	$18.3	$18.8	$20.3	$22.7	$26.5
Total	**$4,894.2**	**$5,126.5**	**$5,388.4**	**$5,965.1**	**$6,335.4**
General					
Unused Land	$2.3	$2.3	$2.3	$2.3	$2.3
Right of Use Land	$7.6	$7.6	$9.1	$10.3	$11.2
Buildings	$384.2	$411.2	$638.5	$720.0	$786.0
Right of Use Buildings	$15.3	$11.5	$7.0	$7.9	$8.6
Office Furniture & Equipment	$49.1	$52.0	$55.7	$62.9	$68.6
Vehicles & Equipment	$201.8	$211.0	$221.2	$259.9	$285.4
Computer Development & Equipment	$171.4	$180.5	$197.8	$404.9	$443.9
Communication, Protection & Control	$179.3	$179.9	$184.1	$144.8	$144.8
Tools & Equipment	$36.0	$35.6	$24.0	$27.0	$27.0
Total	**$1,046.9**	**$1,091.6**	**$1,339.8**	**$1,640.0**	**$1,777.9**
TOTAL PLANT IN SERVICE	**$17,795.7**	**$18,239.6**	**$19,021.2**	**$22,129.2**	**$23,451.5**

SRRP Q5 Reference: Work from Home Policies

a) Does SaskPower have a work from home policy? If so, please provide a copy. If not, please discuss why not.

b) What proportion of SaskPower's workforce works from home either part-time or full-time.

Response:

a) Yes, copy is attached
b) The proportion of SaskPower employees that have a formal part time or full time work from home arrangement is 22.5%.

SASKPOWER REMOTE WORK POLICY

SaskPower
Powering our future®

Division	Human Resources
Policy Title	SaskPower Remote Work Policy
Issue Date	05/16/2025
Revision Frequency	5 years

POLICY STATEMENT

To provide SaskPower employees the opportunity to work remotely where it is operationally and economically feasible.

APPLICABILITY

Applies to:	All SaskPower employees.

ELIGIBILITY

Please refer to the "*Working Remotely – Requirements & Eligibility*" and "*Working Remotely – FAQ's*" documents for further information.

OVERVIEW

Formal Remote Work Arrangement: A fixed schedule that is consistent from week to week or month to month. (i.e. 1 day a week – every Monday, 3 days a week – Monday, Wednesday, Friday or 5 days a week or every third week once per month).

Ad-hoc Remote Work Arrangement: Unscheduled and/or infrequent requests to work from home equivalent to up to 4 days/month (except in extenuating circumstances).

CONDITIONS

Duration:
All remote work arrangements will be reviewed on an annual basis. If the employee or SaskPower wishes to end a formal arrangement, in either case, a minimum of 14 calendar days notice will be given. Under certain circumstances, SaskPower retains the right and discretion to direct an employee to immediately return to work at their primary work location.

Performance and Standards: All employees are expected to continue to meet performance targets and business expectations while working from home. If at any time an employee's productivity and performance declines or they are placed on a performance improvement plan; the remote work arrangement and/or ad hoc request will be ended.

Hours of Work: All employees will be expected to maintain their regular hours of work as they would from their primary work location. If an employee is on flexible or reduced hours, this may continue while working remotely. If the employee wishes to change their hours of work, the applicable form and/or application must be submitted for approval.

Parking: SaskPower Management employees with an approved Work from Home schedule of 80 to 100% are not eligible for Regina downtown parking.

Communication and Accessibility: Employees on a formal arrangement must attend to their primary work location for meetings, training, etc. at the request of their leader. Employees on an ad hoc or formal remote work arrangement who wish to work at a location other than their primary residence (including on a temporary basis) require their leader's approval.

Dependent Care: Working from home is not a substitute for child or dependent care. While it is understood that children or dependents could be at home during work hours, the employees primary focus will be on their work.

Time Entry: All employees working remotely, formal or ad-hoc, must enter days worked from home in their timesheet using the work from home code. Reports will be provided to leaders on a monthly basis to confirm appropriate time code entry.

Information Security: Employees are responsible for maintaining the security and confidentiality of all SaskPower equipment and information and must adhere to the "Information Technology Management" policy. Employees must immediately report any suspected or known incident of any unauthorized access or disclosure of company resources, documentation, or information.

Expenses: Employees are responsible for all expenses relating to their home office, including rent, internet and utilities.

SaskPower will not reimburse any employees working remotely to travel into their primary work location. Any costs occurred such as parking, meals, etc. will be at the employee's expense. Refer to the *"Procurement Card & Employee Expense Policy."*

Health and Safety: Employees must adhere to all SaskPower health and safety policies and provide their manager with a completed safety checklist and evacuation plan (permanent requests). All health and safety training must remain current. All safety incidents and injuries must be reported immediately.

All employees who are working remotely are required to have the following at their work location:

- Fire extinguisher
- First aid kit
- Evacuation plan
- Smoke detector/alarm
- Completed HARA (permanent requests)

SaskPower will not reimburse employees for safety supplies they are required to have at their remote work location.

Meetings with customers and other SaskPower employees will not occur at a remote work location.

Insurance: SaskPower recommends you consult with your insurance provider and review your current home insurance policy.

Operations and Functionality: If at any time the employee's work is interrupted due to a power outage or other service function for a prolonged amount of time, their leader must be informed. If the interruption will be greater than one day, the employee will be required to return to their primary work location until they can resume job functions at their remote work location.

Employees will contact the SaskPower Service Desk at (306) 566-2013 for any IT issues, password resets, logon issues, etc.

Tax Implications: SaskPower will not provide any advice or guidance on the tax implications of having a home office. At the employee's request, SaskPower will provide a T2200.

Remote office requirements: Refer to "*Working Remotely – Requirements & Eligibility*"

APPLICATION AND APPROVALS – IN-PROVINCE REMOTE WORK

Application: Employees wishing to submit a formal request must complete a *remote work application* online with appropriate approvals as required. To submit your application, please visit the '*Remote Work*' EIN page.

APPLICATION AND APPROVALS – OUT-OF-PROVINCE REMOTE WORK

Application: Employees wishing to submit an out-of-province formal remote work arrangement must complete a *remote work application* online with appropriate approvals as required. To submit your application, please visit the '*Remote Work*' EIN page.

Out-of-province remote work applications will require additional information and approvals as specified below:

- A business case must be prepared by the employee wishing to enroll in an out-of-province remote work arrangement. The business case must indicate the critical need for the arrangement as it relates to sustaining business operations. Out-of-province requests will only be considered if supported by the business. If circumstances change and there is no longer a business need for the arrangement, SaskPower will have the authority to end the arrangement at any time.
- The arrangement and business case must be approved via email by the employee's leadership up to and including the President and Chief Executive Officer.

RESPONSIBILITIES

Manager, Director and Executive:

- In no circumstance shall this arrangement create extra costs for the company or reduce the productivity level and results expected of your team.
- Ensure the employee's performance expectations and conditions of employment are clearly defined when granting both formal and informal requests.
- All formal requests must be approved by the employee's Manager and/or Director. Vice – President approval will be required on any requests more than 40%. All formal remote work requests must be sent to Human Resources once approved. Employees will be required to track the days working remotely in their timesheet using the work from home code.
- All ad-hoc requests must be approved by the employee's manager and cannot exceed 4 days per month. Extenuating circumstances (e.g. recovering from surgery but still able to work) may allow an employee to exceed 4 days per month and requires Director approvals.
- All ad-hoc entries will be audited on a monthly basis. Employees will be required to track the days working remotely in their timesheet using the work from home code. By leaders approving time sheet entries, they are confirming all remote work time has been entered. It will be up to an employee's leader to keep a record of the ad-hoc requests from employees.
- Ensure all relevant policies, guidelines and conditions are being followed.
- For those employees on a formal remote work arrangement, develop a plan for weekly meetings, coaching and identify days employees will come into their primary work location if applicable.

Employee:

- Prior to requesting a formal remote work arrangement, review the document, "*Working Remotely - Items to Consider Before Applying*".

- Thoroughly review all policies, documents and guidelines related to remote work.
- Designate a space in your home which is free from distraction and adheres to all health and safety standards and meets ergonomic regulations.
- Employees on an approved formal request must maintain all items listed in the "*Working Remotely – Requirements & Eligibility*" document.
- Take precautions necessary to secure and protect SaskPower property, documents and information in compliance with "*Information Technology Management*" and "*Personal Information Privacy"* polices.
- Maintain quality and quantity of work and adhere to all performance expectations outlined by your leader. It is also expected that you will uphold SaskPower's corporate values and adhere to the SaskPower Code of Conduct.
- Practice safe work habits and report all accidents and injuries to SaskPower Health and Wellness.
- Enter all days worked remotely in the timesheet using the work from home code.

GOVERNANCE

It is the responsibility of both the employee and their leader to ensure that the employee working remotely is adhering to all conditions and responsibilities of this policy. If at any time any part of this policy is not being met by the employee, SaskPower has the right to end the arrangement immediately. SaskPower reserves the right to amend and revoke this policy at any time.

RESOURCES

Related Policies:

SaskPower Code of Conduct

Personal Information Privacy

Information Technology Services Standard

Procurement Card & Employee Expense

Regina Downtown Parking Policy

SRRP Q6 Reference: Artificial Intelligence

a) Does SaskPower have an artificial intelligence use policy? If so, please provide it. If not, please explain why not.

b) Please discuss how SaskPower currently uses AI and what additional applications it anticipates in the test years.

Response:

a)

SaskPower has an Artificial Intelligence Security Standard as well as AI General Guidelines. Copies of these are attached.

b)

SaskPower is applying artificial intelligence in a measured, value driven way, focused on improving productivity, decision making, security, and operational efficiency while managing risk and cost. AI is governed centrally within Technology & Security, with a strong emphasis on responsible use, data protection, and leveraging existing enterprise platforms before acquiring new tools.

Today, SaskPower's primary AI benefits come from employee productivity and embedded intelligence. Microsoft 365 Copilot is deployed to support staff through tasks such as legislative scanning, document analysis, and coding assistance, delivering meaningful time savings without exposing sensitive data outside the organization's environment.

SaskPower is also leveraging AI embedded within core enterprise systems rather than building standalone solutions. Platforms such as SAP, IFS, and ADMS use AI and machine learning to enhance HR processes, optimize field service scheduling, accelerate outage detection and restoration, and improve real-time operational decision making.

In analytics, SaskPower has been investing in machine learning for asset management and system planning. Examples include transformer load prediction models using AMI data and exploratory AI work in rural line design to test whether AI can replicate or improve complex engineering decisions. These initiatives support more data driven infrastructure planning and capital allocation.

From a cybersecurity perspective, AI tools such as Security Copilot and Sentinel are being used to interpret security alerts, automate low value responses, and allow specialists to focus on higher risk threats, improving both speed and effectiveness of incident response.

SaskPower is piloting targeted use cases, learning from results, and scaling only where clear business value exists—positioning SaskPower to capture future AI benefits while maintaining operational reliability and financial discipline.

Artificial Intelligence (AI) Security Standard

Enterprise Security

Internal Use Only

Table of Contents

1. Introduction

1.1 Purpose

This document outlines the security standards necessary to protect AI systems from threats and vulnerabilities, ensuring their safe and ethical use.

This document covers the AI lifecycle and address key dimensions such as validity, reliability, safety, security, transparency, explainability, privacy, and fairness. This document aims to incorporate trustworthiness considerations into the design, development, deployment, and use of AI products and services

1.2 Audience and Scope

This standard applies to the Board of Directors of SaskPower, SaskPower officers, employees, and contractors as well as directors, employees and contractors of SaskPower subsidiaries and service vendors (collectively “Personnel”).

This standard applies to all AI systems developed, deployed, purchased, or maintained by SaskPower, including machine learning models, data processing pipelines, AI integrated services & software, and AI-driven applications.

When dealing with NERC CIP governed assets or sites, NERC CIP cyber security policies and standards must be adhered to at a minimum. If you have any questions on what qualifies as a NERC CIP asset or site, please contact your manager.

1.3 Compliance

Non-compliance of this standard by SaskPower employees or employees of contractors providing services to SaskPower may lead to disciplinary action up to and including dismissal.

All new systems must be designed to comply with this standard prior to being introduced into SaskPower’s environment.

Existing systems must develop a remediation plan to get into compliance to this standard and for remediation of any new vulnerabilities within the timelines provided by SaskPower’s Enterprise Security.

The requirements below are **minimum** standards. It is always acceptable, and may be recommended, to implement measures that are more stringent than what is documented based on the overall risk of the solution.

1.4 Exceptions

Where compliance cannot be met or enforced due to system capabilities or application limitation, an exception must be filed, reviewed, and approved. Exception requests must be submitted by Enterprise Security on behalf of the Risk Owner.

2. Governance Framework

Governance of AI tools is a critical aspect that ensures the responsible development, deployment, and use of artificial intelligence technologies. Effective governance frameworks typically include regulations, ethical guidelines, and oversight mechanisms to address issues such as bias, privacy, transparency, and accountability.

3. Compliance

Use of AI tools must be consistent with all applicable laws (including the Freedom of Information and Protection of Privacy (FOIP) Act and legislation relating to artificial intelligence, copyright, human rights, data privacy, and data security, etc.), and all applicable regulatory requirements.

AI Users must always comply with the SaskPower's ***Code of Conduct, Corporate Privacy Policy, Respectful Workplace Policy***, and ***Acceptable Use Standard***, when using AI Tools. Please refer to those policies for additional information on what might be considered inappropriate or unlawful use.

All generative AI inputs and outputs are subject to the ***Records and Information Management Policy*** and ***Data Classification Standard***.

Use of AI tools, other than an enterprise platform procured or approved by the SaskPower Technology & Security department is prohibited on SaskPower owned devices. It is the responsibility of personnel to ensure the use of any AI platforms for business purposes on devices is approved in advance as per the Governance section below.

AI models and services are considered to have the same level of sensitivity as the data which is:

- Used to design and train them
- Entered as a prompt

4. Governance

4.1 Approved General Use AI Tools

The following tools have been identified as approved for general use within SaskPower. These services are approved for use with SaskPower specific or identifiable data; however, usage must adhere to the requirements in this document regarding compliance, ethical use, code generation, and data security. User authentication is required prior to use of the following:

- Azure AI Services
- Microsoft Copilot

Note: While use of Azure AI has been approved, new implementations or integrations with this service are subject to standard Security Assessments and processes.

4.2 Additional General/Public Use AI Tools

Widely available, or public AI tools which, are not listed in the section above, such as ChatGPT, Gemini, DALL-E, etc., will be periodically assessed for use based on their risk profile.

It is important to understand that data entered into these tools is considered the same as releasing data to the public. Therefore, use of such tools must adhere to the requirements in this document regarding compliance, ethical use, code generation, and data security.

4.2.1 Approval Process for Additional Tools

SaskPower will maintain a process for approving additional AI tools based on their security risk profile. Tools which do not meet a minimum level of security compliance will be prohibited from use.

As risk profiles can fluctuate over time, these tools will be continuously evaluated and will potentially be blocked without notice. Should an AI tool be critical to a business function, a security assessment must be conducted, regardless of the risk profile. This may reduce the risk of the tool being blocked due to a small change in security risk.

Tools which do not meet the minimum level of security compliance must be assessed and approved by Enterprise Security prior to use.

4.3 Purchased AI Software or Services

Purchased AI software or services must follow Enterprise Procurement and Enterprise Security Policies. Appropriate Legal, Privacy, and Security reviews must be conducted prior to purchase.

5. Ethical AI Use

Ensure that any confidential, proprietary, or sensitive SaskPower information is not used as input into any public AI tool, such as those in section 4.2. Examples of sensitive information include passwords and other credentials, protected health information, copyright protected information, personnel material or PII, information from documents marked Confidential, Restricted, or any other non-public information that might be of use to competitors or harmful to SaskPower if disclosed. This may breach your or SaskPower's obligations to keep certain information confidential and secure, risks widespread disclosure, and may cause SaskPower's rights to that information to be challenged.

Use of any AI tool must adhere to the following:

- All outputs must be reviewed by humans before being used. The human reviewer is fully accountable for the accuracy of the output.
- Uploading personal information (names, addresses, likenesses, etc.) about any person into any AI tool is prohibited.

6. AI Code Generation

Generative AI tools can be specialized and specifically trained to generate source code in a lot of programming languages. These resources can help developers save time, but there are also risks regarding the quality of the code (pushing vulnerabilities) or the insertion of backdoors if an attacker has compromised the AI model.

6.1 Check AI-generated source code systematically

The source code generated by AI must be subject to security measures to ensure that it is not harmful:

- Prohibition of automatic execution of AI-generated source code.
- Prohibition of automatic commit of AI-generated source code to repositories.
- Check that the libraries referenced in the result of the source code generated by AI are harmless.
- The quality of the source code generated from sufficiently sophisticated standard queries needs to be checked regularly by a human.

6.2 AI source code generation for critical application modules

Generative AI tools used to generate blocks of source code intended for critical modules, such as the ones below, must have additional human review processes and verification:

- Cryptography modules (authentication, encryption, signatures, etc.).
- User and administrator access rights management modules.
- Sensitive data processing modules.

7. Data Security

Unless the AI tools have enterprise controls in place which ensure that inputs and outputs stay under SaskPower's full control, or unless input mitigations fully redact sensitive information, sensitive information must not be provided as inputs to AI for any purpose, including for training or testing generative AI models outside of SaskPower's control. Examples of AI systems which have enterprise controls in place are listed in section 4.1.

As newer Information Protection/Data Loss Protection technology evolves, a user or business area must agree to allow an AI technology or tool to be monitored to ensure SaskPower data and information remains protected.

Providing inputs to AI without enterprise controls is considered the same as releasing that data to the public.

7.1 Data Access Control

- Use role-based access control (RBAC) to restrict data access based on user roles and responsibilities.
- Implement multi-factor authentication (MFA) for accessing sensitive data.

8. Resiliency

To prevent malfunctions or inconsistencies in the responses provided by the AI model, it is recommended that, at minimum, there is an AI system bypass procedure for users, to meet business needs. The deployment of generative AI and LLM systems generally involves Graphics Processing Units (GPUs) to enhance system performance, whether in the training or production phase. These GPUs may process sensitive data linked to the AI model's operations. To protect against data leaks, these GPU hardware components should be dedicated to the AI system and not be shared with other business applications. GPUs, on the other hand, can be shared between several AI models, but only if they have the same level of sensitivity and same security requirements.

Dedicate GPU components to the AI system Physical GPU components should be dedicated to the processing carried out by the AI system. In the case of virtualization, hypervisors with access to GPU cards should be dedicated to the AI system or at least have a hardware filtering function (e.g.: Input-Output Memory Management Unit (IOMMU)) to restrict virtual machine access to the memory on these GPU cards.

9. System Security

The hosting of the AI system, regardless of the phase it is in, must be considered. The level of security must be consistent with SaskPower's security requirements, and the confidentiality requirements for the data used in each phase.

AI models are considered to have the same level of sensitivity as the data used to design and train them.

9.1 Isolation

Isolate each phase of the AI system into a dedicated environment. The technical environments corresponding to each phase of the AI system's lifecycle should be siloed (development, test, quality assurance (QA), production, etc.). Additionally, is recommended that the AI system be siloed into dedicated logical zones within each environment, to limit the risk of an attacker who has compromised the system moving laterally

Isolation may involve:

- Network isolation: each environment is integrated into a physically or logically dedicated network.
- System isolation: each environment has its own dedicated physical servers or hypervisors.
- Storage isolation: each environment has its own storage hardware or dedicated disks. At the very least, there will be a logical segmentation.
- Accounts and secrets isolation: each environment has its own users and administrators accounts and separate credentials.

Implement a secure Internet gateway for an AI system hosted on the Internet. For AI systems which are hosted on the Internet, it is recommended to follow the isolation best practices, in particular:

- implement a reverse-proxy function before accessing the AI system web service.
- set up two logical areas for network filtering using firewalls: external filtering on the Internet front end and internal filtering before accessing the AI system.
- do not use any of the entity's internal directories for authentication on the AI system.
- avoid mutualization of security functions on the same hypervisor in the secure Internet gateway (firewalls, reverse-proxy, logging server, etc.).

9.2 Automation

Limit automatic actions performed by an AI system handling uncontrolled inputs. It is strongly recommended that automated actions on the network be limited when these are triggered by an AI system and uncontrolled inputs (e.g. data from the Internet or emails, etc.).

An AI system must be configured so that it cannot automatically execute critical information system actions. These actions may be critical from a business point of view (banking transactions, production of public content, physical impact on humans, etc.) or critical actions on the IT infrastructure (reconfiguration of network components, creation of privileged users, deployment of virtual machines, etc.).

9.3 Integrations

The AI system's interaction with other business applications or other technical resources can be source of vulnerabilities. These interactions often take the form of plugins offered by AI model editors. These plugins will enable the AI system to be interconnected with tools and social networks, or potentially critical infrastructure components (identity management, network resources, etc.). These interactions can also facilitate the lateralization of an attacker on the network, if they take advantage of a vulnerability in the AI system.

All the interactions and network flows of the AI system must be documented and approved. Network flows between the AI system and other resources must comply with SaskPower Security Standards:

- They must be strictly filtered at network level, encrypted and authenticated.
- They must use secure protocols (e.g. OpenID Connect) when using an identity provider.
- In addition to authentication, the authorization of access to the resource must also be checked.
- They must be logged at the appropriate level of granularity.

Do not integrate any AI tool with internal SaskPower software without following Security and IT processes to approve the use of such tools.

9.4 Privileged Access Control

All privileged operations on the AI system must comply with secure administration best practices, in particular:

- Privileged operations must be defined. Initializing or triggering these operations must be approved:
  - re-training
  - modification of data sets
  - new interconnection with an application
  - change of hosting, etc.
- Privileged operations must be carried out using dedicated accounts and from a dedicated administration workstation.
- The principle of least privilege must be applied, and temporary authentication tokens should be used.
- The development environment must be managed to the same level of security as the production environment.
- The roles and access rights of AI system developers and administrators must be strictly defined and applied during the project.

9.5 Model Security

9.5.1 Model Validation

- Perform rigorous testing and validation of AI models before deployment.
- Use cross-validation, A/B testing, and other techniques to ensure model accuracy and reliability.

9.5.2 Model Monitoring

- Continuously monitor AI models for security, including performance degradation and anomalies, which can be indicators of compromise.
- Implement automated alerting systems to notify stakeholders of potential issues.

9.5.3 Input and Output Validation

These functions should be implemented to protect against data leak or model leak in responses:

- A function to filter malicious user queries before these are sent to the model.
- A filter function for queries deemed to be non-legitimate from a business point of view.
- A filter function for internal model information (parameters, training) in the responses.
- A filter function for information defined as sensitive in responses (e.g. private details, project references, etc.).
- A limit on the size of responses (maximum number of tokens)

9.6 Model Development and Training

The issue of data confidentiality has already been covered in a previous general recommendation. In particular, and regarding the number of vulnerabilities published on generative AI tools, it should be assumed that a user with access to a trained AI model could potentially have access to the training data for this model. To reduce the risks associated with the confidentiality of training data, it is sometimes necessary to use an anonymization process or generate a synthetic dataset from the original raw data. In some cases, these measures can resolve the issue of protecting information, but it is important to be vigilant about attacks aimed at retrieving the initial information from anonymized or synthetic data: attacks by attribute or membership inference, re-identification based on cross-referencing with other datasets, etc.

It is strongly recommended to train a model with data of a level of sensitivity consistent with the users' access rights. It is strongly recommended not to re-train an AI model directly in production.

The use of external libraries and modules must be considered during the design phase of the project, to identify potential vulnerabilities associated with these modules. The goal is to provide the maximum level of protection against a supply-chain-attack targeting components required for the proper functioning of the AI system.

9.6.1 Fairness and Non-Discrimination

- Ensure AI systems are designed and trained to avoid biases and discrimination.
- Regularly audit AI systems for fairness and take corrective actions if biases are detected.

9.6.2 Transparency and Explainability

- Develop AI systems that provide clear and understandable explanations for their decisions and actions.
- Implement mechanisms to allow users to query and understand AI decision-making processes.

9.6.3 Accountability

- Implement processes for addressing and rectifying harmful or unintended consequences of AI system decisions.

9.6.4 Privacy and Consent

- Ensure AI systems respect user privacy and obtain explicit consent for data collection and usage.
- Implement privacy-preserving techniques, such as differential privacy, to protect user data.

9.6.5 Human Oversight

- Maintain human oversight over critical AI system decisions, especially those impacting safety, security, and ethical considerations.

- Develop protocols for human intervention in AI system operations when necessary.

9.6.6 Data Integrity

The integrity of the model's training data should be ensured throughout the training cycle. This protection may take the form of systematic checking the signature or hash of the files used (or compressed archives with all this data).

The integrity of the trained model files should be protected and regular checks done to ensure that these have not been altered. This recommendation also applies by extension to all the files inherent to the proper working of the AI system (scripts, binaries, etc.).

10. Deployment

The deployment of a generative AI system must be based on a secure deployment environment, (ex. fully harnessed and robust Continuous Integration/Continuous Delivery or Deployment (CI/CD) chains). CI/CD chains must be operated from an administration system and from dedicated, robust administrator workstations.

A security assessment must be carried out prior to deployment to production to test the vulnerabilities inherent to AI systems (adversarial attacks, etc.). Robustness and security tests of AI systems are recommended. These tests can be:

- Standard penetration tests on the usual technical components of an AI system: web servers, orchestrator, database, etc.
- Security tests on developments made in the AI system (using SAST or DAST tools, for example).
- Automated tests specifically targeting vulnerabilities related to AI models (adversarial attacks, model extraction, etc.).
- Manual tests specifically aimed at testing the robustness of a generative AI model in more sophisticated attack scenarios.

11. Operational Security

11.1 Patch Management

Regularly update and patch AI systems, including software, libraries, and dependencies in accordance with the ***Security Remediation and Patch Management Standard.*** Implement automated patch management tools to streamline the process.

11.2 Audit and Logging

Actions on the AI system must be logged with adequate level of information granularity, in particular, regarding the inputs and outputs of the AI model. For the purposes of traceability and explicability of the AI system, it is important to make a clear distinction between the queries made by users and the data sent to the AI model. For performance and security reasons, user queries may be subject to specific pre-processing and formatting before being sent to the model. These two pieces of information are crucial in facilitating the management of an incident and must be traceable in the AI system's application logs. All processing carried out on the AI system should be logged at the correct level of granularity, in particular:

- User queries (ensuring these are secured if they contain sensitive data).
- The input processing carried out on this query before it is sent to the model.
- Calls to plugins.
- Calls for additional data.

- The processing carried out by the output filters.
- Responses to users.

12. User Training

Users should be educated about the potential security risks of AI, including data breaches, misuse of AI algorithms, and unauthorized access. Training programs should cover the basics of AI, its applications, and the importance of security. On-going education and awareness programs should be in place to keep stakeholders informed about emerging threats.

13. Third-Party Management

13.1 Vendor Assessment

- Evaluate third-party vendors for compliance with AI and SaskPower security and privacy standards before engaging their services.
- Conduct regular security assessments of third-party vendors to ensure ongoing compliance.

13.2 Contractual Obligations

- Include specific security requirements in contracts with third-party vendors, including data protection, incident response, and compliance obligations.
- Establish clear accountability and liability clauses for security breaches involving third-party vendors.

14. Continuous Improvement

14.1 Review and Update

System performance and trustworthiness may evolve and shift over time, once an AI system is deployed and put into operation. This phenomenon, generally known as drift, can degrade the value of the AI system to the organization and increase the likelihood of negative impacts. Regular monitoring of AI systems' performance and trustworthiness enhances organizations' ability to detect and respond to drift and thus sustain an AI system's value once deployed.

15. References

Enterprise Security Policy
Records and Information Management Policy
Acceptable Use Standard
Data Classification Standard
Artificial Intelligence (AI) Security Standard References - All Documents
AI Guidelines for SaskPower Personnel

16. Glossary

Term	Description
AI Model	In the context of this standard, an AI model refers to a neural network and its parameters
AI System	An AI system encompasses all the technical components of an application based on an AI model: implementation of this AI model, front-end services for users, databases, logging, etc.
Critical Business	Elements (systems, processes, applications, etc.) that are essential for a

	company's core operations and survival; their failure or disruption can lead to significant financial losses, operational disruptions, or reputational damage.
Critical Modules	These are specific parts of a software program that, if they malfunction or fail, could lead to serious consequences, such as system crashes, data loss, safety hazards, or security breaches.
Enterprise Controls	Enterprise controls refer to the processes and systems an organization uses to manage, monitor, and control its operations and risks, ensuring compliance with internal policies and external regulations. Some examples are Data Loss Prevention, Network Monitoring/Segregation, Isolation, Patch Management, etc.
Generative AI	Generative AI is a subsection of artificial intelligence, focused on creating models trained to generate content (text, images, videos, etc.) from a specific corpus of training data.
General Use	"General use" signifies a broad, widespread, or typical application or purpose, rather than a specific or limited one. A "general-purpose" tool can be used for various tasks.
GPU	Graphics processing unit, a specialized processor originally designed to accelerate graphics rendering. GPUs can process many pieces of data simultaneously, making them useful for machine learning, video editing, and gaming applications.
IOMMU	An IOMMU (Input-Output Memory Management Unit) is a hardware component that connects a DMA-capable I/O bus to system memory, mapping device-visible virtual addresses to physical addresses, which is crucial for virtualization and DMA protection.
Large Language Model (LLM)	A category of generative AI models that can generate text close to natural human language and which are generally trained on a large dataset.
Purchased Services or Software	Purchased services or software refers to software or service that a user or organization buys, typically through a one-time payment or a subscription fee.
Query	A query (or prompt) refers to the instruction in text form sent by the user to the AI system.

17. Appendices

Artificial Intelligence General Guidelines

Enterprise Architecture

Internal Use Only

Table of Contents

1. Introduction

1.1 Purpose

The purpose of this document is to provide guidance to users of Artificial Intelligence (AI) services.

1.2 Audience and Scope

These guidelines are intended for general users of AI services. These users typically consume AI services only.

There is an advanced version of the guidelines for users who have more in depth use cases for AI such as developers, data scientists and data analysts. These users may consume services that exist or develop new AI services internally.

1.3 Compliance

The guidelines show users how existing policies at SaskPower apply, therefore, failure to comply is the same as not complying with those same policies with the same consequences as outlined in each policy.

1.4 Exceptions

As these are guidelines, exceptions do not apply.

2. Guidelines

2.1 Principles

The concept of Responsible AI is based on principles that have similar intent to our Code of Conduct Policy (in particular the sections regarding handling of information) and the Security Data Classification Standard which describes the identification and treatment of the various classes of data.

The Code of Conduct sections that are most relevant are listed below:

- **Accounting Standards and Controls**: These AI technologies are in a sense, assets of the company and should be treated as described in the policy. Costs of these services would also be relevant to these guidelines.
- **Handling SaskPower Information – Confidentiality**: The guidelines refer to information, privacy concerns and similar topics this section of the policy covers.
- **Copyright**: There are copyright concerns involved in AI usage and the policy describes general rules in handling of copyrighted material.
- **Propriety of Information**: This section of the policy covers issues around protecting proprietary information and sharing that information with Public AI services would violate the policy.
- **Record Retention**: This section refers to handling of SaskPower records which comes into play with AI services in situations where you are providing information to the service, especially if it is a public AI service.
- **Related Policies**: There are other policies/standards that can apply depending on circumstances such as the Security Data Classification Standard for one example. The Code of Conduct Policy has a long list of related policies you should be aware of.

2.2 Public vs. Private AI

Some of these AI services are controlled by other companies like Google or OpenAI which we regard as *Public AI Services*. These services use AI models these companies trained on data they control. When you use these services your prompts and their outputs are fed back into their models to improve them and you have no control over this process.

Other services are regarded as *Private AI services* because we can control their access to our important data and information. At SaskPower we just launched Bing Chat Enterprise that provides AI services in an environment internal to SaskPower. These technologies are much safer than publicly available ones.

2.3 Private AI Use Case

Public AI use cases should be avoided, where possible, due to risk of data leaks, but the following use case provides guidance going forward for SaskPower personnel who have need to use an AI chatbot:

Bing Chat Enterprise

You want to write an email, but the subject matter is only to be used within SaskPower. You prompt Bing Chat Enterprise by asking it to write the email for you.

Recommendation

Because Bing Chat Enterprise is private to SaskPower you do not have to worry about the sensitive nature of the email. You can prompt Bing Chat Enterprise with the specific details just like you would if sending an email to your manager and asked about the same topic. The reason is that Bing Chat Enterprise is managed by T&S and not a public service like the regular public Bing Chat. You can tell because there is a green tag on the top right that says "Protected". This is to indicate that all information is contained within our systems and therefore not accessible by the general public.

You review the generated content to ensure it complies with our existing policies such as the Code of Conduct Policy. The content does align to those policies, and you review the accuracy of the content by checking the sources quoted by Bing Chat and determine the content is appropriate and of sufficient quality that you are confident using it. Bing Chat Enterprise has helped you complete the task but you were responsible in using that content appropriately.

3. References

Resources

Bing Chat Enterprise

https://www.bing.com/search?q=Bing+AI&showconv=1

EIN Announcement of Bing Chat Enterprise Launch

https://saskpower.sharepoint.com/sites/intranet/news-events/news/Pages/Artificial-Intelligent-Chat-that-is-Safe-for-the-Workplace.aspx

LinkedIn Learning Course for Bing Chat

https://www.linkedin.com/learning/streamlining-your-work-with-microsoft-bing-chat/

LinkedIn Learning Course for Generative AI
https://www.linkedin.com/learning/what-is-generative-ai/

4. Glossary

Term	Description
AI	Artificial Intelligence
Public AI	Publicly controlled services and data.
Private AI	SaskPower controlled services and data.

5. Appendices

SRRP Q7 Reference: Affordability

a) Does SaskPower have a working definition of bill affordability or energy poverty? For example, a Low-Income Cut-Off (LICO) threshold used to identify households who may need assistance with their bills or who may benefit from support implementing energy efficiency measures?

b) Does SaskPower have bill payment or bill assistance programs for low-income customers or customers having difficulty paying their electricity bills? If so, please provide a description of any existing programs and the approximate number of customers who accessed the programs in each of the past three years.

c) Please provide SaskPower's actual bad debt for the past three years and forecast for the test years.

d) Has SaskPower noticed an increase in bad debt and/or accounts in arrears in the past three years? Please discuss and quantify to the extent possible.

e) Please provide a summary of SaskPower's collection practices including policies for disconnecting or load limiting customers in arrears.

Response:

a) SaskPower uses Statistics Canada's most recent (currently 2023) Low Income Measure (LIM) thresholds by income source and household size to inform eligibility thresholds for income-based affordability programs targeting low- to mid-income households. LIM is the low-income threshold and 150% of LIM the mid income threshold.

b) SaskPower offers the following special care and flexibility options to customers who are struggling to keep up with bill payments:

- **Payment deferral:** SaskPower may permit customers to defer a lump sum owing and make payments toward that balance at any time during the deferral period. Deferrals are established for periods ranging from six months to a year, with the option to extend based on individual circumstances. Customers must continue to pay their current monthly bills during this time.

- **Installment payment plan:** SaskPower works with customers who have outstanding balances to establish structured monthly payment arrangements, enabling them to resolve their arrears over a specified period. To make it easier, eligible customers can create their own installment plan on-line, via chat or through a phone call to SaskPower.

	2022-23	2023-24	2024-25
Installment payment plans created	37,900	32,800	40,500

- **Equalization payment plan or budget billing:** This plan makes it easier for customers to budget their power bills by allowing the customer to pay the same amount each month and avoid unexpected high bills. Proactive outreach for customers with large credit or debit balances.

	2022-23	2023-24	2024-25
Customers on Equalization Payment Plans	79,100	78,300	76,400

- **Indigenous organization support:** SaskPower provides different levels of assistance for those customers supported by Jordan's Principle through Indigenous Services Canada or through the Metis Nation of Saskatchewan's Homelessness Prevention Program.

SaskPower also provides self-generation and affordability programs, including energy efficiency education and tools, to help customers reduce their electricity use, as outline in Section 2.1 of the application:

- **Online Energy Assessment for Homes:** This online tool, available at saskpower.com, provides customers with energy-saving tips based on an evaluation of power and natural gas consumption. The tool considers a customer's lighting, heating, insulation and appliances, and estimates the power and natural gas used by the customer. Customers receive customized information about their consumption and tips for no-cost actions that could lead to savings.
- **Energy Assistance Program:** This is a free program for low-income customers offering a home walkthrough, energy coaching and the installation of several energy-saving products, including LED lighting, low-flow water measures, a drying rack and a smart thermostat upgrade. Customers can save up to an estimated $230 per year on their electricity, gas and water bills.
- **Northern First Nations Home Retrofit Program:** SaskPower provides this program to customers in Northern First Nations communities who use electric heat as their primary heating source. Eligible customers will receive no-cost home retrofits, including upgraded insulation, insulating pipes, and installation of LED lights and upgraded windows and doors.
- **Northern Indigenous New Homes Program:** As part of SaskPower's commitment to energy efficiency and affordability, the utility has launched the Indigenous New Homes Rebate. The program offers financial support to eligible Indigenous communities to help make new home builds more energy efficient during the construction phase. Many customers in northern communities rely on electric heat to heat their homes, which can cause high power bills. Homes constructed with the Indigenous New Homes Rebate could save between $1,000-$3,000

annually on their power bills based on the energy performance standards of the home constructed. The rebate is open to eligible Indigenous communities in Northern Saskatchewan who rely on electric heat as their primary heating source.

- **Energy Efficiency Discounts Program:** SaskPower and SaskEnergy collaborate as Crowns in an annual partnership with local retailers to offer point of purchase discounts on a variety of energy efficient products including lighting controls, smart thermostats, select ENERGY STAR washing machines and dishwashers, low flow shower heads and aerators, bathroom ventilation fans and insulation measures.

- **Home Efficiency Retrofit Rebate Program:** In partnership with SaskEnergy, this program offers rebates to eligible homeowners to enhance their homes' comfort and efficiency with high performance windows, doors, insulation and air sealing retrofits. To be eligible for the rebates, homeowners must be registered under the "Canada Greener Homes" grant through Natural Resources Canada (NRCan). The program offers a maximum rebate of up to $1,800. An additional $200 is available to help cover the cost of pre- and post-upgrade EnerGuide evaluations.

- **Commercial Energy Optimization Program:** This program assists commercial customers with affordability through free consulting services. This service identifies energy-saving opportunities, guides project development and identifies financial options through three services: The Energy Support Service (ESS) for small and medium business customers; the Energy Coach Services for large commercial businesses; and Custom Incentive Services. ESS identifies opportunities, develops business cases, reports and tracks energy management, and trains stakeholders. Energy Coach Services provides participants with all services in ESS, plus up to $30,000 to hire or retain a dedicated energy champion who will identify, lead, develop and implement projects. Custom Incentive Services provides financial incentives to upgrade facilities with more energy efficient equipment, thus improving affordability.

- **Commercial Space and Water Heater Rebate Program:** SaskPower partners with SaskEnergy to offer rebates on high-efficiency equipment, including air conditioning roof-top units and electronically commutated motor pumps, to maximize energy cost savings.

- **Net Metering Program:** This residential, farm and business program provides an opportunity for customers to generate their own electricity and deliver surplus energy to the grid. Participants must use an approved environmentally preferred technology with up to 100 kilowatts of nominal generating capacity. Customers are compensated at 7.5 cents per kilowatt hour for excess generation they deliver to the grid. A bi-directional meter keeps track of the electricity to and from the grid for billing purposes.

- **Residential Customer Engagement:** This initiative features a variety of educational outreach efforts, including energy efficiency campaigns on social media, participation in trade shows, street fairs, and community events across the province. These activities create valuable opportunities to connect with customers in their own communities. Through accessible education and practical tools, the program empowers customers to make informed choices about energy use — helping them save both power and money.

c) The following table provides SaskPower's actual bad debt for the past three years and forecast for the test years:

Bad debt expense

(in millions)	Actual **2022-23**	Actual **2023-24**	Actual **2024-25**	Forecast **2025-26**	Forecast **2026-27**
Bad debt expense	$ 5.5	$ 8.4	$ 3.8	$ 4.0	$ 5.0
TOTAL BAD DEBT EXPENSE	**$ 5.5**	**$ 8.4**	**$ 3.8**	**$ 4.0**	**$ 5.0**

d) After all collection activities were completed, pandemic-related accounts in arrears were written off in 2022-23 and 2023-24, therefore bad debt expense peaked in those years. Accounts receivable in arrears has been consistently dropping over the past three years, returning very close to pre-pandemic levels.

e) SaskPower bills are due prior to the issuance of the next invoice. Accounts are considered current if only the most recent bill is outstanding or if no balance is owing. When an account becomes 30 days overdue, SaskPower initiates payment reminders and the arrears process to obtain payment or set up payment arrangements.

SaskPower makes numerous attempts to contact the customer to set up payment arrangements. SaskPower demonstrates flexibility for customers having trouble paying their electricity bills by offering installment payment plans, payment deferrals, and equalization payment plans.

During the winter months (November 1 - March 31), SaskPower does not disconnect residential properties for non-payment. Instead, a load-limiting device is installed, or, if the property has a smart meter, a remote load limit is activated. In both cases, electricity usage is restricted to 40 amps, which is typically sufficient to run essential household items such as a furnace, lighting, and a refrigerator. Load limiting is not applied to farms, properties heated by electricity, or locations where meter access is not possible, such as locked electrical rooms. If the account remains unpaid, full disconnection occurs once regular arrears procedures resume.

If a customer is disconnected or load-limited due to non-payment, service restoration requires payment of the outstanding balance, a security deposit, and a reconnection fee. Where a disconnection lasts more than 13 days, a final bill is issued. Unpaid final bills are sent to an external collection agency after 90 days.

SRRP Q8 Reference: Payments to the Province and section 7.0 of the Application

a) For the period of 2021/22 through 2026/27 please provide a table itemizing all actual or forecast payments to the Province of Saskatchewan including water rentals, corporate capital taxes, coal royalties, dividends and any other payments to the Province.

b) SaskPower states that the application is based on the principle that "…SaskPower must set rates that will collect sufficient revenue to recover all reasonable costs and to provide a return to the shareholder." Please discuss how SaskPower's application is consistent with this principle given that SaskPower is proposing rates for 2025/26 that are forecast to result in a net loss of $147 million in 2025/26.

Response:

a) The following table shows direct contributions to the Province of Saskatchewan from the period of 2021-22 through 2026-27:

Direct Contributions to the Province of Saskatchewan

(in millions)	Actual **2021-22**	Actual **2022-23**	Actual **2023-24**	Actual **2024-25**	Forecast **2025-26**	Forecast **2026-27**
Interest on long & short-term debt	$ 285	$ 290	$ 319	$ 353	$ 389	$ 428
OBPS carbon tax	-	-	267	276	365	-
Corporate capital tax	51	54	57	64	70	76
Grants in lieu GRF	27	28	31	31	30	33
Coal royalties	8	6	5	4	6	10
Water rentals	18	20	16	18	18	24
Dividends	3	-	18	-	-	-
Total	**$ 392**	**$ 398**	**$ 713**	**$ 746**	**$ 878**	**$ 571**

b) The forecasted loss in 2025-26 is largely a result of accruing unbudgeted carbon tax expense. As negotiations are ongoing between the Government of Saskatchewan and the federal government, direction on the Output-Based Pricing System (OBPS) compliance payments is uncertain at this time. Given this uncertainty, SaskPower has elected to forgo its targeted return on equity to ensure affordable power for our customers.

SRRP Q9 Reference: Corporate Risks

a) Please update the response to the Round 1 SRRP Q7 from the 2022 and 2023 rate application indicating what SaskPower considers to be the largest business or financial risks it faces (e.g. natural gas prices; interest rates; sales growth or decline) and provide an estimate of the potential upper and lower range of effects of these risks on operating income, return on equity and debt ratio in 2025/26 and 2026/27.

b) Please provide a separate version of the response to a) which includes the potential impact of losing one of SaskPower's largest industrial customers.

c) Does SaskPower consider cybersecurity vulnerabilities to be a material business or financial risk? Please discuss why or why not.

d) Does SaskPower consider US tariffs to be a material business or financial risk? Please discuss why or why not?

e) With reference to the federal government's engagement on strengthening industrial carbon pricing announced in December 2025 (see: https://www.canada.ca/en/environment-climate-change/news/2025/12/government-of-canada-launches-engagement-to-strengthen-industrial-carbon-pricing-and-secure-major-clean-energy-investments.html) please discuss if SaskPower views carbon pricing as a material business risk, particularly given the decision to re-power coal generation. Please discuss including any mitigation measures considered by SaskPower.

Response:

a) As part of SaskPower's strategic planning process, we have identified a number of risks and uncertainties that could impact the achievement of our business objectives. The following risk factors represent challenges SaskPower considers the most significant in the short to medium term:

- Regulation
- Financial sustainability
- Infrastructure, reliability, and energy supply
- Energy policy
- Indigenous engagement
- Security
- Safety
- Project delivery and supply chain
- People and skills

The business or financial risks that could have a significant impact on operating income and/or return on equity in the short term, including 2025-26 and 2026-27, are discussed below with alignment to the top corporate risk profile identified.

SaskPower
Powering our future®

2026 AND 2027 RATE APPLICATION
SRRP INTERROGATORIES

Capital expenditures | Project Delivery and Supply Chain / Financial Sustainability / Regulation

SaskPower has identified the need to invest significant amounts of capital in long-term projects to ensure continuing reliability as well as maintain, upgrade and expand infrastructure. New regulations, stakeholder expectations, and financial constraints are placing increasing demands on SaskPower and are all competing for operating and capital resources.

SaskPower's Business Plan assumes capital expenditures of nearly $1.8 billion in 2025-26 and $1.7 billion in 2026-27. A $100 million change in the capital budget is estimated to have an $8 million impact on net income.

Rate increase | Financial Sustainability

SaskPower's Business Plan assumes an interim rate increase of 3.9% effective February 1, 2026, followed by 3.9% effective February 1, 2027. The rate increase is subject to review by the Saskatchewan Rate Review Panel with final approval by Cabinet.

Each 1% change in the recommended rate increase is estimated to have a $30 million impact on SaskPower's net income in 2025-26 and $31 million in 2026-27.

Saskatchewan electricity sales volumes | Financial Sustainability / Energy Policy

SaskPower is forecasting Saskatchewan electricity sales growth of 2.4% in 2025-26, resulting in total annual electricity sales of 24,551 GWh. In 2026-27, the Corporation is forecasting sales growth of 3.8%, resulting in a total annual sales volume of 25,489 GWh. However, actual sales volumes are subject to several variables, including economic conditions, number of customers and weather.

The impact of a change in the sales volumes forecast will differ by customer class. For example, the financial impact of a 100 GWh change in sales volumes to the Residential customer class is forecast to have a $16 million impact on SaskPower's net income. A 100 GWh change in Power customer class sales is estimated to have a $5 million impact on SaskPower's financial results. These estimates were calculated before applying the impact of the proposed rate increases.

Natural gas prices | Financial Sustainability / Infrastructure, Reliability, and Energy Supply / Regulation

SaskPower uses a diversified fleet of generation and fuel sources to produce electricity in Saskatchewan. This includes coal, natural gas, hydro, wind, imports, waste heat, and solar. Natural gas generation is forecast to provide between 41% to 48% of the Corporation's electrical needs in 2025-26 and 2026-27, which serves as SaskPower's largest generation source in terms of percentage of electricity supplied. SaskPower is forecasting to consume 102.0 million GJ of natural gas in 2025-26 and 85.3 million GJ in 2026-27.

Natural gas prices are subject to significant volatility due to fluctuations in the market price. To mitigate that risk, the Corporation has hedges in place to fix the price of natural gas on up to 50% of its forecasted natural gas purchases in the coming calendar year.

The estimated impact to SaskPower's fuel and purchased power costs of a $1/GJ change in the price of natural gas is $50 million in 2025-26 and $47 million in 2026-27.

Hydro volumes | Financial Sustainability / Infrastructure, Reliability, and Energy Supply
Hydro generation is forecast to provide between 10% to 13% of SaskPower's generation needs in 2025-26 and 2026-27. Hydro generation is the least expensive marginal cost source of electricity in SaskPower's fleet. When hydro generation is lower than expected, it must be replaced by other, more expensive sources of electricity, such as natural gas or imports.

The actual amount of hydro generation is largely dependent on water levels in the rivers that feed SaskPower's hydro generation facilities. A 10% change in the level of hydro generation is estimated to have a $5 million impact on SaskPower's fuel and purchased power budget in 2025-26 and $8 million in 2026-27.

The sensitivity analysis on the following page provides additional information on the financial impact of changes in the Corporation's planning assumptions.

Sensitivity Analysis

Item	Assumptions 2025-26	Assumptions 2026-27	Sensitivity analysis	Net income impact 2025-26	Net income impact 2026-27	ROE impact 2025-26	ROE impact 2026-27	Per cent debt impact 2025-26	Per cent debt impact 2026-27
Revenue									
Rate increase (%)	**3.9%**	**3.9%**	1% increase in rate increase assumption	$ 30	$ 31	1.1%	1.1%	-0.4%	-0.4%
Sask Sales Growth (%)	**2.4%**	**3.8%**	100 GWh increase in power customer class	5	5	0.2%	0.2%	-0.1%	-0.1%
			100 GWh increase in residential customer class	16	16	0.6%	0.5%	-0.2%	-0.2%
Fuel and purchased power									
Natural gas price ($/GJ)	**$ 3.33**	**$ 4.66**	$1/GJ change in natural gas price assumption	$ (50)	$ (47)	-1.8%	-1.7%	0.7%	0.6%
Hydro generation (GWh)	**2,726.9**	**3,582.2**	10% change in hydro generation assumption	5	8	0.2%	0.3%	-0.1%	-0.1%
Capital									
Capital spend ($ millions)	**$1,786.9**	**$1,691.6**	$100 million change in capital budget	$ (8)	$ (8)	-0.3%	-0.3%	0.9%	0.8%
Short-term interest rates (%)	**2.5%**	**2.5%**	1% change in short-term interest rates	(11)	(13)	-0.4%	-0.4%	0.2%	0.2%
Long-term interest rates (%)	**4.6%**	**4.6%**	1% change in long-term interest rates	(12)	(10)	-0.4%	-0.4%	0.2%	0.1%

b) The sensitivity analysis below provides additional information on the financial impact of SaskPower losing one of its largest industrial customers.

Item	Assumptions 2025-26	Assumptions 2026-27	Sensitivity analysis	Net income impact 2025-26	Net income impact 2026-27	ROE impact 2025-26	ROE impact 2026-27	Per cent debt impact 2025-26	Per cent debt impact 2026-27
Revenue									
Sask Sales Reduction (GWh)	**2,798.5**	**2,794.3**	Loss of largest industrial customer	$ (133)	$ (126)	-4.9%	-4.6%	1.8%	1.6%

C) Cybersecurity is identified as a top corporate risk at SaskPower. A breach of physical security or cybersecurity has the potential for significant financial impact, reputational impact, or operational disruption.

D) Supply Chain has been identified as a top corporate risk and considers the impacts tariffs may have in delivering projects on schedule or within budget.

E) Industrial carbon pricing risk is inherently mitigated through the development and maintenance of a diversified generation portfolio that includes coal-fired, natural gas-fired, hydroelectric, and renewable generation, as well as small and large nuclear reactors. A diversified portfolio reduces SaskPower's exposure to changes in the regulatory framework that could result in future carbon tax obligations by limiting reliance on any single fuel type or emissions profile. This approach supports system reliability, energy security and affordability while providing flexibility to adapt to evolving regulatory policies and emissions requirements. SaskPower will continue to monitor carbon pricing developments and adjust its mitigation strategies as policy frameworks evolve.

SRRP Q10 Reference: Carbon Charges

a) With reference to the federal carbon tax variance account (FCTVA) described on page 34 of SaskPower's 2024-25 annual report, please:

   i. Provide a breakdown of the federal carbon charge cumulative payments/payables of $1,114 million that have been:

      i. remitted to the Government of Canada
      ii. remitted to the Province of Saskatchewan
      iii. remain as payables in SaskPower's accounts
      iv. any other treatment.

   ii. Provide a breakout of the "other recoveries/expenses" between interest and carbon charges associated with exported generation.

   iii. Explain why the balance in the FCTVA is not included in SaskPower's financial statements if it reflects actual revenue collected and payables recorded by SaskPower.

   iv. Quantify the amounts paid to certain independent power producers and explain the rationale for making such payments.

   v. SaskPower's annual report indicates a cumulative undercollection of approximately $8 million at the end of 2024/25. Given SaskPower has paused collection of the carbon charge rider, does SaskPower intend to collect that amount from customers in the future?

b) Please provide a table that shows, by each actual and forecast year, the carbon charge revenues from each of the federal government and the provincial government that have been returned to SaskPower through grants or other mechanisms.

c) SaskPower's 2024-25 annual report states at page 14 that "effective April 1, 2025 SaskPower paused the collection of the federal carbon charge rate rider as mandated by the Government of Saskatchewan." Please provide a copy of the direction from the provincial government mandating the pause in collection of the federal carbon charge rate rider.

d) SaskPower's 2024-25 annual report states at page 14 that "SaskPower's electric heat relief program delivered $2.1 million in savings to residential and farm customers who must rely on electric heat through a 60% reduction in the federal carbon charge that was collected on their power bills between November 1, 2024 and March 31, 2025." Please:

   i. Provide a description of what customers were eligible. Was it any customer with electric heat or only customers who do not have access to natural gas?

   ii. Explain how the 60% reduction was calculated.

   iii. Discuss if SaskPower develop this program on its own or if it was directed or mandated by the provincial government?

   iv. Please explain how these reductions are reflected in the schedule provided in the response to part (a).

e) SaskPower's 2024-25 annual report states at page 34 that in July 2023, the Government of Canada approved the Saskatchewan Output-Based Performance Standards (OBPS) as a replacement for the Federal OBPS Program retroactive to January 1, 2023. Please provide a copy of the program details and the specific approvals received from the Government of Canada.

f) SaskPower states at page 6 of the application that it assumes the OBPS will not apply to the Corporation starting in 2026-27. Please discuss the basis for that assumption and provide an update on whether SaskPower continues to believe the assumption is reasonable.

g) Is SaskPower aware of any other electric utilities in Canada who are exempt from OBPS or equivalent provincial program requirements? If so, please provide details.

h) Please provide an estimate of the OBPS charge that would apply in 2026-27, 2027-28 and 2028-29 if the same basic framework were in place as for 2025-26, adjusted for anticipated changes in the carbon price and SaskPower's generation mix. Please show the calculation including assumed carbon prices, generation mix and carbon intensity per generation type.

i) SaskPower's application states at page 19 that the anticipated OBPS carbon charge in 2025-26 will be $368 million. Please discuss:

   i. What portion of that amount has already been remitted to the government? If any amount has not yet been paid, please indicate when SaskPower anticipates it will be paid.

   ii. Please provide the calculation of the $368 million based on SaskPower's generation mix and showing the carbon intensities by generation source and the carbon charge per unit assumed in the calculation.

Response:

a)

i. Carbon Tax Payments

(in millions)		ECCC[1]		IPP[2]		Total		Payments		Payable
Total Federal Carbon Tax	**$**	**493**	**$**	**3**	**$**	**496**	**$**	**496**	**$**	**-**

(in millions)		OBPS[3]		IPP[2]		Total		Payments		Payable
2023 calendar year	$	249	$	3	$	252	$	249	$	3
2024 calendar year		280		5		285		280		5
2025 calendar year		80		1		81		-		81
Total Provincial Carbon Tax	**$**	**609**	**$**	**9**	**$**	**618**	**$**	**529**	**$**	**89**
Total Carbon Tax Payments/Payables	**$**	**1,102**	**$**	**12**	**$**	**1,114**	**$**	**1,025**	**$**	**89**

1. Environment and Climate Change Canada (ECCC)
2. Independent Power Producers (IPP)
3. Saskatchewan Output-Based Performance Standards (OBPS) Program

ii. Other recoveries (expenses)

(in millions)		Interest income		Exports		Chinook[1]		Electric heat relief		Total other recoveries (expenses)
Total 2019 calendar year	$	-	$	1	$	(4)	$	-	$	(3)
Total 2020 calendar year		1		2		-		-		3
Total 2021 calendar year		1		6		-		-		7
Total 2022 calendar year		6		5		-		-		11
Total federal (2019 - 2022 calendar years)	**$**	**8**	**$**	**14**	**$**	**(4)**	**$**	**-**	**$**	**18**
Total 2023 calendar year		13		16		-				29
Total 2024 calendar year		9		9		-		2		20
Total 2025 calendar year (three months)		-		1		-		2		3
Total provincial	**$**	**22**	**$**	**26**	**$**	**-**	**$**	**4**	**$**	**52**
Total cumulative balance, March 31, 2025	**$**	**30**	**$**	**40**	**$**	**(4)**	**$**	**4**	**$**	**70**

1. Federal carbon charges on natural gas purchased for the Chinook Power Station prior to it becoming a registered facility with ECCC.

iii. SaskPower accumulated differences between the federal carbon charge revenue collected from customers and the federal carbon tax owing in the Federal Carbon Tax Variance Account (FCTVA). The balance in the FCTVA was not included in the financial statements but rather was either recovered from or refunded to customers as part of future federal carbon charge rates.

iv. Please see response provided in (a)(i) for payments made to Independent Power Producers (IPPs). The reason the payments are made directly to the IPPs is that they directly own these generation facilities and are therefore responsible as the regulated emitter to file the annual compliance returns. SaskPower reimburses these carbon tax amounts to the IPPs as required by the power purchase agreements.

v. SaskPower does not intend to collect the $8 million under-collected amount from customers in the future.

b) Federal funding

The Government of Canada, as represented by Environment and Climate Change Canada (ECCC), entered into a funding agreement with SaskPower to establish the terms and conditions that would allow for the return of any Output Based Pricing System (OBPS) payments to the corporation. The Future Electricity Fund (FEF) was created to support projects undertaken by SaskPower that would result in the production and provision of clean electricity and/or decrease the use of greenhouse gas (GHG) emitting energy sources. The Decarbonization Incentive Program (DIP) was also established by the federal government as a method to return federal OBPS payments to SaskPower. The DIP program supports projects to accelerate the deployment of commercially available and proven low-carbon technologies and processes that will further reduce GHG emissions.

Provincial funding

In July 2023, the Government of Canada approved the Saskatchewan Output-Based Performance Standards (OBPS) as a replacement for the Federal OBPS Program retroactive to January 1, 2023. Through the Saskatchewan OBPS program, half of the compliance payments remitted by SaskPower are returned to the Corporation through the Clean Electricity Transition Grant (CETG) to support clean electricity operating costs, including renewable power purchase agreements, demand-side management programs, and renewable power imports.

The table below includes the carbon charge revenues that have been returned to SaskPower through grants or other mechanisms from both the federal and provincial governments as described above.

Carbon charge revenue returned to SaskPower					
(in millions)	Actual **2022-23**	Actual **2023-24**	Actual **2024-25**	Forecast **2025-26**	Forecast **2026-27**
Federal Government	$ 7	$ 48	$ 75	$ 166	$ 164
Provincial Government	-	-	140	175	-

c) SaskPower considers the public announcement from the Government of Saskatchewan dated March 27, 2025, as formal direction to stop the collection of the federal carbon charge rate rider. A copy of the announcement is attached.

d) Please see below for details on the Electric Heat Relief program:

i. Residential and farm customers who rely on electricity as their primary source of home heating were eligible to receive the Electric Heat Relief from SaskPower.
ii. Customers with electric home heating generally have high electricity consumption. While SaskPower's meters accurately record the amount of electricity consumed, the meters cannot track whether the electricity was used for home heating or another use. It is estimated that an average of 50% to 60% of electricity consumption is used for electric home heating during winter months and the reduction was set to 60%.
iii. SaskPower developed this program in conjunction with the provincial government.
iv. The Electric Heat Relief program ran twice. From January 1, 2024, to April 30, 2024, the program provided $1.3 million relief to SaskPower customers. From November 1, 2024, to April 30, 2025, the program provided $2.1 million relief. This relief is reflected in the other recoveries (expense) column of the Federal Carbon Tax Variance Account (FCTVA) table in part (a).

e) **Saskatchewan Output-Based Performance Standards Program**

Please refer to the following documents for details on Saskatchewan's Output-Based Pricing System (OBPS) Program:

- *The Management and Reduction of Greenhouse Gases Act*

- *The Management and Reduction of Greenhouse Gases (General and Electricity Producer) Regulations*
- *The Management and Reduction of Greenhouse Gases (Standards and Compliance) Regulations, 2023*

Approvals from the Government of Canada

Amendment to the Greenhouse Gas Pollution Pricing Act

Please refer to the *Order Amending Part 2 of Schedule 1 to the Greenhouse Gas Pollution Pricing Act* (the Order) for the Government of Canada's approval of the Saskatchewan OBPS Program. The objective of the Order is to avoid regulatory duplication and support the full implementation of the provincial OBPS Program in Saskatchewan, which has been assessed by the Department of the Environment to meet the updated federal benchmark that applies over the 2023-2030 period.

The Order deletes the name of Saskatchewan from Part 2 of Schedule 1 to the *Greenhouse Gas Pollution Pricing Act*., effectively removing the application of the federal OBPS program to Saskatchewan's electricity generation and natural gas transmission pipeline sectors as of January 1, 2023.

Equivalency Agreement

A proposed equivalency agreement between the governments of Canada and Saskatchewan was finalized and published on December 29, 2018.

The existing Equivalency Agreement allows Saskatchewan to implement a fleet-based provincial regulation, enabling coal operation beyond federal retirement dates — but only while an Equivalency Agreement is in force. The current agreement only covers 2025–2026; renewal is required for 2027–2029.

f) As negotiations between the Government of Saskatchewan and the federal government are ongoing, it is uncertain what the direction will be on the OBPS program. Due to this uncertainty, the Crown Investments Corporation has directed that any OBPS amounts be removed from future years. Any changes to the OBPS that materially impact SaskPower's financial projections will be provided and explained in the mid-application update that will be filed later in the review process.

g) SaskPower is not aware of any other electric utilities in Canada that are exempt from OBPS or equivalent provincial program requirements. While Prince Edward Island, Manitoba, the

Yukon, and Nunavut continue to fall under the Federal OBPS program, all other provinces and territories (except Québec) apply a provincial or territorial carbon pricing system for industry. Québec applies a cap-and-trade system rather than a direct OBPS.

h) Forecasted carbon tonnes are as follows:

Fiscal Year	CO_2 Tonnes
2026/27	12,577,799

- CO_2 tonnes are calculated using forecasted generation and unit emission intensities.

	Emission Intensity (tonnes CO_2/MWh)		
Fiscal Year	**Coal**	**SPC Gas**	**IPP Gas**
2026/27	1.02	0.41	0.35

- Taxable CO_2 tonnes are calculated by factoring in the allowable carbon thresholds which are as follows:

	Allowable Threshold (tonnes CO_2/MWh)		
Calendar Year	**Gas Unit***	**Gas Unit**	**Coal Unit**
2026	370	164	482

*Allowable threshold applicable to SaskPower grandfathered units

- The CO_2 tax calculation utilizes the following federal rates:

Calendar Year	CO_2 Tax Rate ($/tonne CO2)
2026	110

Notes:

1. **Information on estimated OBPS charges is speculative at this point. We will provide additional information once an agreement between Saskatchewan and Canada is finalized.**
2. **The 2027-28 and 2028-29 periods are outside of the scope of the current rate application and have therefore been excluded.**

i)

i. At the time of the Rate Application, the forecasted OBPS carbon charge of \$368 million in 2025-26 has not been remitted to the government. As negotiations between the Government of Saskatchewan and the federal government are ongoing, it is uncertain what the direction will be on the OBPS program. Any changes to the OBPS that materially impact SaskPower's financial projections will be provided and explained in the mid-application update that will be filed later in the review process.

ii. Forecasted carbon tonnes and charges are as follows:

Fiscal Year	CO_2 Tonnes	Taxable CO_2 Tonnes	CO_2 Tax (\$ Million)
2025/26	11,213,496	3,727,889	368.0

- CO_2 tonnes are calculated using forecasted/actual generation and unit emission intensities.

	Emission Intensity (tonnes CO_2/MWh)		
Fiscal Year	**Coal**	**SPC Gas**	**IPP Gas**
2025/26	0.98	0.39	0.37

- Taxable CO_2 tonnes are calculated by factoring in the allowable carbon thresholds which are as follows:

	Allowable Threshold (tonnes CO_2/MWh)		
Calendar Year	**Gas Unit***	**Gas Unit**	**Coal Unit**
2025	370	206	510
2026	370	164	482

*Allowable threshold applicable to SaskPower grandfathered units

- The CO_2 tax calculation utilizes the following federal rates:

Calendar Year	CO_2 Tax Rate (\$/tonne CO_2)
2025	95
2026	110

Saskatchewan

Saskatchewan is the First Province in Canada to be Carbon Tax Free

Released on March 27, 2025

Effective April 1, Saskatchewan will be the first province in Canada to be carbon tax free.

The Government of Saskatchewan will pause the industrial carbon tax rate under its Output-Based Performance Standards (OBPS) Program, a decision that will provide immediate financial relief to families, farms, businesses and industry. The carbon tax rate rider will be removed from all SaskPower bills. This will save hundreds of dollars a year for Saskatchewan families and businesses.

"Today, we are making Saskatchewan the first carbon tax free province in Canada," Premier Scott Moe said. "In taking the lead on the removal of this harmful tax, we hope all federal leaders will support our position and allow the provinces to regulate in this area without imposing the federal backstop."

"Saskatchewan led on the removal of the carbon tax on home heating last year, saving families in our province over $400 on their household SaskEnergy bills," Minister of Crown Investments Corporation Jeremy Harrison said. "Now we are leading again as the first province in Canada to remove the industrial carbon tax on electricity generation, delivering further savings for Saskatchewan families, businesses and industries on their SaskPower bills."

In the face of the ongoing tariff threats and the rising cost of living, Saskatchewan is taking decisive steps to protect Saskatchewan businesses and residents from economic uncertainty and unnecessary taxation.

"Now more than ever, the world needs our clean and sustainable, food, fuel and fertilizer" Environment Minister Travis Keisig said. "This is not the time to risk undermining our economic growth and prosperity. Pausing the industrial carbon tax will allow industries to grow and operate sustainably while maintaining our economic competitiveness during these uncertain times."

Saskatchewan is home to some of the most sustainable products on the planet and has the food, fuel, fertilizer and critical minerals the world needs. By eliminating industrial carbon costs which are often passed directly on to consumers – the province is acting to protect affordability and economic competitiveness.

This decision will foster an economic environment where industries can feel confident to make investments, increase production, and protect the jobs and families they support.

While the industrial carbon tax rate is paused, the Government of Saskatchewan will continue to engage with industry on the future of Saskatchewan's OBPS system.

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For more information, contact:

Matthew Glover
Executive Council
Regina
Phone: 306-787-2127
Email: matthew.glover@gov.sk.ca

SRRP Q11 Reference: Grant Funding

a) Please provide any documentation, direction, or guidance received regarding the Clean Electricity Transition Grant (CETG).

b) For each of the 2022-23, 2023–24, 2024–25, 2025–26, and 2026–27 fiscal years, please provide a schedule that:

i. Identifies all sources of actual or forecast grant funding, including but not limited to the CETG.

ii. Lists each grant individually by source, the amount received, and the specific purpose or activity it was intended to support.

iii. Shows where each grant is reflected in the financial statements, including the specific revenue, OM&A or capital line items or cost categories in which grant funding has been applied. Please provide a clear mapping of grant dollars to OM&A and capital expenditures.

iv. Reconciles the total OM&A and capital grant funding noted in the 2024–25 Annual Report funding referenced in the 2026–27 GRA.

Response:

b)

i)

(thousands) Grant	Actuals 2022-23	Actuals 2023-24	Actuals 2024-25	Forecast 2025-26	Forecast 2026-27	Total Cash received April 1, 2022 - Jan 31, 2026
Infrastructure Canada	$3,034	$1,391	$384	$1,559	$3,490	$11,483
Saskatchewan Public Safety Agency	568	440	612	1,246	616	1,557
Natural Resource Canada	566	15,507	28,489	11,050	2,343	57,115
SaskBuilds	7,859	3,816	1,448	946	10,931	16,341
Eco-west Canada		-	100	-	-	100
Environment Climate Change Canada						
Future Electricity Funding	7,213	47,740	75,668	166,645	167,306	134,469
Other	1,058	2,259	255	-1,852	-	3,564
Total Environment Climate Change Canada	8,271	49,999	75,924	164,794	167,306	138,033
Government of Saskatchewan	-	-	140,000	361,700	175,000	140,000
Total Grants	$20,297	$71,153	$246,955	$541,293	$359,685	$364,629

iv)

(millions) Grant Name	Actuals 2023-24	Actuals 2024-25	Forecast 2025-26	Business Plan 2026-27
Provincial OBPS - Clean Electricity Transition Grant	-	$140	$175	-
2026-27 GRA table 7.2 - Expense	-	140	175	-

Grant Name	Actuals 2023-24	Actuals 2024-25	Forecast 2025-26	Business Plan 2026-27
OBPS Future Electricity Fund (FEF)	$44	$72	$149	$128
2026-27 GRA table 7.3 - Future electricity fund	44	72	149	128

Project Name	Actuals 2023-24	Actuals 2024-25	Forecast 2025-26	Business Plan 2026-27
Disaster Mitigation and Adaptation Fund (DMAF)	$1		$2	$3
Green Infrastructure Phase II - Smart Grid		1		
Investing in Canada Infrastructure Program (ICIP)	4	1	1	11
OBPS Future Electricity Fund (DIP)				6
Total	$5	$2	$3	$20
2026-27 GRA table 7.3 - Other Funding	5	2	3	20

The rest of the response contains confidential information and cannot be released publicly. However, a complete response has been provided to the Saskatchewan Rate Review Panel for their review.

SRRP Q12 Reference: Financial/Productivity Indicators

a) Please provide a schedule that shows the calculation of SaskPower's actual and forecasted interest coverage ratio for each of the years in the table on page 33 of the application.

Response:

The following table shows the calculation of SaskPower's actual interest coverage ratio for 2024-25 as well as the forecasted interest coverage ratio for 2025-26 and 2026-27.

Interest coverage ratio

(in millions)	Actual **2024-25**	Forecast **2025-26**	Forecast **2026-27**
Net income	$ 75.7	$ (146.7)	$ 78.9
Finance charges	417.7	462.5	458.0
Add back:			
Debt retirement fund earnings	(32.1)	(31.6)	(42.0)
Interest income	(8.4)	(5.4)	(5.5)
Depreciaton and amortization	638.0	675.0	712.3
Earnings before interest, depreciation & amortization	1,171.9	1,027.8	1,296.7
Interest on long-term debt	325.4	364.2	391.2
Interest on short-term debt	26.9	24.3	37.1
Interest on finance leases	131.2	129.4	122.6
Other interest and charges	1.5	1.1	1.1
Gross interest expense	$ 485.0	$ 519.0	$ 552.0
Interest coverage ratio	2.4	2.0	2.3

2026 AND 2027 RATE APPLICATION
SRRP INTERROGATORIES

SRRP Q13 Reference: Business Plan Assumptions

a) For each of the business plan assumptions shown in the table on page 33 of the application, please discuss the information or sources SaskPower considers in developing these assumptions.

Response:

a) SaskPower considers the following information when developing the business plan assumptions:

Inflation rate
SaskPower assumed an inflation rate of 2% when preparing the business plan. Recent global events have caused significant volatility to various input costs which will result in certain expenses increasing at a rate higher than 2%.

SaskPower continues to monitor these impacts and will incorporate any additional cost pressures into the mid-application update.

Annual load growth
The business plan assumptions on annual load growth are based on the 2026 Q1 Load Forecast.

Short-term borrowing rate
SaskPower's short-term borrowing rate forecast is developed using a combination of the three-month Canada forward rate, the three-month Saskatchewan versus three-month Canada spread, and the three-month issuance spread. This base forecast is then adjusted for any floating rate note premiums.

Long-term borrowing rate
SaskPower's long-term borrowing rate forecast is developed using a combination of the five-year Canada forward rate, the 30-year Saskatchewan versus five-year Canada spread, and the 30-year Saskatchewan issuance spread averaged with a combination of the 10-year Canada forward rate, the 30-year Saskatchewan versus 10-year Canada spread, and the 30-year Saskatchewan issuance spread.

2026 AND 2027 RATE APPLICATION
SRRP INTERROGATORIES

Weighted average natural gas price
In the short-to-medium term, forecasted natural gas prices are developed using the 30-day average of NGX AECO forward prices. Forecasted natural gas generation (or consumption) is determined based on the assumptions discussed in the following section. The weighted average natural gas price is then calculated based on the total fuel and purchased power costs for natural gas (including storage and transportation costs) averaged over total natural gas generation volumes.

Gas consumption
Assumptions on SaskPower's gas consumption consider generation needs based on the Q1 Load Forecast. The dispatch of gas units is based on the lowest variable incremental cost units being dispatched to meet SaskPower's energy and ancillary service requirements. The gas unit calculation of variable incremental costs is based on the projected natural gas commodity price, heating values of the gas supplied, heat rate of the natural gas generation, and the variable operation and maintenance cost of the unit or plant.

Capital expenditures
The capital expenditures included in the Rate Application are obtained from the SaskPower capital plan. The overall capital plan is projected over a 15-year forward-looking period and is continually reviewed and revised as priorities change.

SaskPower prioritizes its capital expenditures based on several criteria and objectives, including: providing a reliable energy supply to meet forecasted load requirements; maintaining system reliability, security and power quality; meeting or exceeding regulations and guidelines; and minimizing the cost of electricity for our customers.

SRRP Q14 Reference: Finance Charges

a) Have there have been any changes to SaskPower's debt strategy with respect to how much short-term versus long-term debt SaskPower takes on and the mixture of floating rate debt versus fixed rate debt SaskPower considers to be optimal since the response to the Round 1 SRRP Q13 from the 2022 GRA proceeding? If so, please provide a summary of the changes and an explanation of the rationale for the changes.

Response:

There have been no changes to the debt strategy.

SRRP Q15 Reference: Finance Charges

a) Please provide a schedule showing all long term debt (including any long-term lease obligations) including the date of issue, date of maturity, effective interest rate, coupon rate, par value, unamortized premium, and outstanding amount for each of the last three actual years and forecasts for the test years.

b) Please provide a schedule showing SaskPower's debt in relation to the total debt of the Province of Saskatchewan for each of the last three years.

Response: See schedules on following pages. All amounts in thousands.

Long-term Debt and Capital Leases
2023-Mar-31

Long-term Borrowings:

Transaction Date	Maturity Date	Par Value	Coupon	All-in Issue Yield	Issue Price	Unamortized Premium	Outstanding Amount
1995-May-8	2025-May-30	$100,000	8.75%	8.82%	99.30	-$131	$99,869
2001-Jul-30	2031-Sep-5	$200,000	6.40%	6.49%	98.86	-$1,121	$198,879
2003-Jan-8	2031-Sep-5	$100,000	6.40%	5.91%	106.73	$3,233	$103,233
2003-May-6	2033-Sep-5	$100,000	5.80%	5.90%	98.56	-$793	$99,207
2004-Jan-7	2033-Sep-5	$200,000	5.80%	5.68%	101.67	$1,834	$201,834
2004-Sep-28	2035-Sep-5	$200,000	5.60%	5.50%	101.56	$1,882	$201,882
2005-Feb-8	2037-Mar-5	$150,000	5.00%	5.09%	98.65	-$1,274	$148,726
2005-Apr-29	2037-Mar-5	$150,000	5.00%	5.07%	98.93	-$1,014	$148,986
2006-Feb-17	2037-Mar-5	$100,000	5.00%	4.71%	104.64	$2,908	$102,908
2007-Feb-27	2040-Jun-1	$100,000	4.75%	4.49%	104.38	$3,039	$103,039
2008-Mar-25	2040-Jun-1	$250,000	4.75%	4.67%	101.29	$2,289	$252,289
2008-Dec-19	2040-Jun-1	$100,000	4.71%	4.71%	100.00	$0	$100,000
2010-Aug-31	2040-Jun-1	$200,000	4.75%	4.27%	107.96	$11,498	$211,498
2012-Nov-7	2042-Feb-3	$200,000	3.40%	3.22%	103.42	$5,108	$205,108
2013-Feb-20	2042-Feb-3	$200,000	3.40%	3.54%	97.56	-$3,705	$196,295
2013-Oct-2	2045-Jun-2	$400,000	3.90%	3.97%	98.74	-$4,133	$395,867
2014-Jan-10	2045-Jun-2	$200,000	3.90%	3.95%	99.15	-$1,391	$198,609
2014-Mar-6	2054-Mar-5	$100,000	3.75%	3.76%	99.71	-$258	$99,742
2014-May-2	2054-Mar-5	$175,000	3.75%	3.71%	100.89	$1,374	$176,374
2014-Oct-2	2045-Jun-2	$200,000	3.90%	3.43%	108.85	$14,491	$214,491
2015-Feb-5	2045-Jun-2	$200,000	3.90%	2.72%	124.14	$38,953	$238,953
2015-May-26	2046-Dec-2	$200,000	2.75%	3.15%	91.99	-$13,381	$186,619
2015-Oct-15	2046-Dec-2	$200,000	2.75%	3.44%	86.95	-$22,125	$177,875
2016-Jan-19	2046-Dec-2	$200,000	2.75%	3.34%	88.69	-$19,225	$180,775
2016-Jul-12	2046-Dec-2	$150,000	2.75%	2.85%	97.94	-$2,622	$147,378
2016-Oct-13	2046-Dec-2	$200,000	2.75%	3.00%	95.09	-$8,387	$191,613
2017-Jan-17	2048-Jun-2	$200,000	3.30%	3.35%	99.07	-$1,635	$198,365
2017-Aug-17	2054-Mar-5	$150,000	3.75%	3.19%	112.10	$16,549	$166,549
2018-Aug-8	2050-Jun-2	$200,000	3.10%	3.18%	98.46	-$2,808	$197,192
2018-Sep-12	2058-Jun-2	$200,000	2.95%	3.13%	95.89	-$7,706	$192,294
2019-Mar-26	2050-Jun-2	$150,000	3.10%	2.81%	105.92	$8,124	$158,124
2019-Jun-11	2028-Dec-2	$175,000	3.05%	2.34%	105.96	$6,523	$181,523
2020-Mar-23	2023-Apr-1	$150,000	1.97%	1.97%	99.94	-$0	$150,000
2020-Apr-2	2024-Jun-3	$200,000	3.20%	1.79%	105.61	$3,257	$203,257
2020-Jun-22	2030-Jun-2	$100,000	2.20%	1.53%	106.19	$4,564	$104,564
2020-Jul-22	2025-Sep-2	$100,000	0.80%	0.93%	99.38	-$300	$99,700
2022-May-9	2052-Dec-2	$180,000	2.80%	4.09%	77.63	-$39,666	$140,334
2022-Jun-23	2052-Dec-2	$300,000	2.80%	4.29%	74.78	-$74,725	$225,275
2022-Nov-4	2031-Jun-2	$350,000	4.18%	4.18%	100.00	$0	$350,000
2023-Jan-18	2062-Jun-2	$120,000	3.80%	3.85%	99.08	-$1,103	$118,897
Total LTD:		**$7,150,000**				**-$81,877**	**$7,068,123**
Capital Leases:							**$903,272**
Total:							**$7,971,395**

Total Provincial Debt	**$29,962,559**

Long-term Debt and Capital Leases
2024-Mar-31

Long-term Borrowings:

Transaction Date	Maturity Date	Par Value	Coupon	All-in Issue Yield	Issue Price	Unamortized Premium	Outstanding Amount
1995-May-8	2025-May-30	$100,000	8.75%	8.82%	99.30	-$73	$99,927
2001-Jul-30	2031-Sep-5	$200,000	6.40%	6.49%	98.86	-$1,018	$198,982
2003-Jan-8	2031-Sep-5	$100,000	6.40%	5.91%	106.73	$2,928	$102,928
2003-May-6	2033-Sep-5	$100,000	5.80%	5.90%	98.56	-$736	$99,264
2004-Jan-7	2033-Sep-5	$200,000	5.80%	5.68%	101.67	$1,701	$201,701
2004-Sep-28	2035-Sep-5	$200,000	5.60%	5.50%	101.56	$1,774	$201,774
2005-Feb-8	2037-Mar-5	$150,000	5.00%	5.09%	98.65	-$1,209	$148,791
2005-Apr-29	2037-Mar-5	$150,000	5.00%	5.07%	98.93	-$963	$149,037
2006-Feb-17	2037-Mar-5	$100,000	5.00%	4.71%	104.64	$2,757	$102,757
2007-Feb-27	2040-Jun-1	$100,000	4.75%	4.49%	104.38	$2,919	$102,919
2008-Mar-25	2040-Jun-1	$250,000	4.75%	4.67%	101.29	$2,200	$252,200
2008-Dec-19	2040-Jun-1	$100,000	4.71%	4.71%	100.00	$0	$100,000
2010-Aug-31	2040-Jun-1	$200,000	4.75%	4.27%	107.96	$11,034	$211,034
2012-Nov-7	2042-Feb-3	$200,000	3.40%	3.22%	103.42	$4,908	$204,908
2013-Feb-20	2042-Feb-3	$200,000	3.40%	3.54%	97.56	-$3,564	$196,436
2013-Oct-2	2045-Jun-2	$400,000	3.90%	3.97%	98.74	-$4,014	$395,986
2014-Jan-10	2045-Jun-2	$200,000	3.90%	3.95%	99.15	-$1,351	$198,649
2014-Mar-6	2054-Mar-5	$100,000	3.75%	3.76%	99.71	-$254	$99,746
2014-May-2	2054-Mar-5	$175,000	3.75%	3.71%	100.89	$1,350	$176,350
2014-Oct-2	2045-Jun-2	$200,000	3.90%	3.43%	108.85	$14,047	$214,047
2015-Feb-5	2045-Jun-2	$200,000	3.90%	2.72%	124.14	$37,656	$237,656
2015-May-26	2046-Dec-2	$200,000	2.75%	3.15%	91.99	-$12,995	$187,005
2015-Oct-15	2046-Dec-2	$200,000	2.75%	3.44%	86.95	-$21,509	$178,491
2016-Jan-19	2046-Dec-2	$200,000	2.75%	3.34%	88.69	-$18,683	$181,317
2016-Jul-12	2046-Dec-2	$150,000	2.75%	2.85%	97.94	-$2,543	$147,457
2016-Oct-13	2046-Dec-2	$200,000	2.75%	3.00%	95.09	-$8,140	$191,860
2017-Jan-17	2048-Jun-2	$200,000	3.30%	3.35%	99.07	-$1,593	$198,407
2017-Aug-17	2054-Mar-5	$150,000	3.75%	3.19%	112.10	$16,229	$166,229
2018-Aug-8	2050-Jun-2	$200,000	3.10%	3.18%	98.46	-$2,742	$197,258
2018-Sep-12	2058-Jun-2	$200,000	2.95%	3.13%	95.89	-$7,584	$192,416
2019-Mar-26	2050-Jun-2	$150,000	3.10%	2.81%	105.92	$7,922	$157,922
2019-Jun-11	2028-Dec-2	$175,000	3.05%	2.34%	105.96	$5,435	$180,435
2020-Apr-2	2024-Jun-3	$200,000	3.20%	1.79%	105.61	$489	$200,489
2020-Jun-22	2030-Jun-2	$100,000	2.20%	1.53%	106.19	$3,957	$103,957
2020-Jul-22	2025-Sep-2	$100,000	0.80%	0.93%	99.38	-$177	$99,823
2022-May-9	2052-Dec-2	$180,000	2.80%	4.09%	77.63	-$38,964	$141,036
2022-Jun-23	2052-Dec-2	$300,000	2.80%	4.29%	74.78	-$73,448	$226,552
2022-Nov-4	2031-Jun-2	$350,000	4.18%	4.18%	100.00	$0	$350,000
2023-Jan-18	2062-Jun-2	$120,000	3.80%	3.85%	99.08	-$1,091	$118,909
2023-May-11	2027-Jun-2	$300,000	3.41%	3.41%	100.00	$0	$300,000
2023-Jun-22	2054-Dec-2	$145,000	4.20%	4.28%	98.71	-$1,849	$143,151
2024-Mar-22	2054-Dec-2	$300,000	4.20%	4.41%	96.47	-$10,586	$289,414
Total LTD:		**$7,745,000**				**-$97,777**	**$7,647,223**
Capital Leases:							**$850,330**
Total:							**$8,497,553**

Total Provincial Debt	**$31,609,124**

Long-term Debt and Capital Leases
2025-Mar-31

Long-term Borrowings:

Transaction Date	Maturity Date	Par Value	Coupon	All-in Issue Yield	Issue Price	Unamortized Premium	Outstanding Amount
1995-May-8	2025-May-30	$100,000	8.75%	8.82%	99.30	-$11	$99,989
2001-Jul-30	2031-Sep-5	$200,000	6.40%	6.49%	98.86	-$908	$199,092
2003-Jan-8	2031-Sep-5	$100,000	6.40%	5.91%	106.73	$2,605	$102,605
2003-May-6	2033-Sep-5	$100,000	5.80%	5.90%	98.56	-$676	$99,324
2004-Jan-7	2033-Sep-5	$200,000	5.80%	5.68%	101.67	$1,561	$201,561
2004-Sep-28	2035-Sep-5	$200,000	5.60%	5.50%	101.56	$1,659	$201,659
2005-Feb-8	2037-Mar-5	$150,000	5.00%	5.09%	98.65	-$1,141	$148,859
2005-Apr-29	2037-Mar-5	$150,000	5.00%	5.07%	98.93	-$909	$149,091
2006-Feb-17	2037-Mar-5	$100,000	5.00%	4.71%	104.64	$2,598	$102,598
2007-Feb-27	2040-Jun-1	$100,000	4.75%	4.49%	104.38	$2,793	$102,793
2008-Mar-25	2040-Jun-1	$250,000	4.75%	4.67%	101.29	$2,107	$252,107
2008-Dec-19	2040-Jun-1	$100,000	4.71%	4.71%	100.00	$0	$100,000
2010-Aug-31	2040-Jun-1	$200,000	4.75%	4.27%	107.96	$10,550	$210,550
2012-Nov-7	2042-Feb-3	$200,000	3.40%	3.22%	103.42	$4,701	$204,701
2013-Feb-20	2042-Feb-3	$200,000	3.40%	3.54%	97.56	-$3,418	$196,582
2013-Oct-2	2045-Jun-2	$400,000	3.90%	3.97%	98.74	-$3,891	$396,109
2014-Jan-10	2045-Jun-2	$200,000	3.90%	3.95%	99.15	-$1,309	$198,691
2014-Mar-6	2054-Mar-5	$100,000	3.75%	3.76%	99.71	-$249	$99,751
2014-May-2	2054-Mar-5	$175,000	3.75%	3.71%	100.89	$1,325	$176,325
2014-Oct-2	2045-Jun-2	$200,000	3.90%	3.43%	108.85	$13,587	$213,587
2015-Feb-5	2045-Jun-2	$200,000	3.90%	2.72%	124.14	$36,324	$236,324
2015-May-26	2046-Dec-2	$200,000	2.75%	3.15%	91.99	-$12,596	$187,404
2015-Oct-15	2046-Dec-2	$200,000	2.75%	3.44%	86.95	-$20,871	$179,129
2016-Jan-19	2046-Dec-2	$200,000	2.75%	3.34%	88.69	-$18,122	$181,878
2016-Jul-12	2046-Dec-2	$150,000	2.75%	2.85%	97.94	-$2,462	$147,538
2016-Oct-13	2046-Dec-2	$200,000	2.75%	3.00%	95.09	-$7,885	$192,115
2017-Jan-17	2048-Jun-2	$200,000	3.30%	3.35%	99.07	-$1,549	$198,451
2017-Aug-17	2054-Mar-5	$150,000	3.75%	3.19%	112.10	$15,900	$165,900
2018-Aug-8	2050-Jun-2	$200,000	3.10%	3.18%	98.46	-$2,673	$197,327
2018-Sep-12	2058-Jun-2	$200,000	2.95%	3.13%	95.89	-$7,458	$192,542
2019-Mar-26	2050-Jun-2	$150,000	3.10%	2.81%	105.92	$7,715	$157,715
2019-Jun-11	2028-Dec-2	$175,000	3.05%	2.34%	105.96	$4,321	$179,321
2020-Jun-22	2030-Jun-2	$100,000	2.20%	1.53%	106.19	$3,341	$103,341
2020-Jul-22	2025-Sep-2	$100,000	0.80%	0.93%	99.38	-$53	$99,947
2022-May-9	2052-Dec-2	$180,000	2.80%	4.09%	77.63	-$38,233	$141,767
2022-Jun-23	2052-Dec-2	$300,000	2.80%	4.29%	74.78	-$72,116	$227,884
2022-Nov-4	2031-Jun-2	$350,000	4.18%	4.18%	100.00	$0	$350,000
2023-Jan-18	2062-Jun-2	$120,000	3.80%	3.85%	99.08	-$1,078	$118,922
2023-May-11	2027-Jun-2	$300,000	3.41%	3.41%	100.00	$0	$300,000
2023-Jun-22	2054-Dec-2	$145,000	4.20%	4.28%	98.71	-$1,819	$143,181
2024-Mar-22	2054-Dec-2	$300,000	4.20%	4.41%	96.47	-$10,419	$289,581
2024-Apr-17	2033-Jun-2	$285,000	3.90%	4.50%	95.54	-$11,633	$273,367
2024-Jun-6	2054-Dec-2	$250,000	4.20%	4.32%	98.01	-$4,908	$245,092
2024-Aug-12	2054-Dec-2	$250,000	4.20%	4.23%	99.52	-$1,195	$248,805
2024-Dec-2	2054-Dec-2	$250,000	4.20%	4.10%	101.75	$4,351	$254,351
list does not include borrowings to be made after Feb 20, 2026							
Total LTD to Feb 20, 2026:		**$8,580,000**				**-$112,144**	**$8,467,856**
Capital Leases:							**$983,918**
Total:							**$9,451,774**

Total Provincial Debt	**$35,221,924**

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Long-term Debt and Capital Leases
2026-Mar-31

Long-term Borrowings:

Transaction Date	Maturity Date	Par Value	Coupon	All-in Issue Yield	Issue Price	Unamortized Premium	Outstanding Amount
2001-Jul-30	2031-Sep-5	$200,000	6.40%	6.49%	98.86	-$790	$199,210
2003-Jan-8	2031-Sep-5	$100,000	6.40%	5.91%	106.73	$2,262	$102,262
2003-May-6	2033-Sep-5	$100,000	5.80%	5.90%	98.56	-$612	$99,388
2004-Jan-7	2033-Sep-5	$200,000	5.80%	5.68%	101.67	$1,412	$201,412
2004-Sep-28	2035-Sep-5	$200,000	5.60%	5.50%	101.56	$1,538	$201,538
2005-Feb-8	2037-Mar-5	$150,000	5.00%	5.09%	98.65	-$1,070	$148,930
2005-Apr-29	2037-Mar-5	$150,000	5.00%	5.07%	98.93	-$852	$149,148
2006-Feb-17	2037-Mar-5	$100,000	5.00%	4.71%	104.64	$2,432	$102,432
2007-Feb-27	2040-Jun-1	$100,000	4.75%	4.49%	104.38	$2,662	$102,662
2008-Mar-25	2040-Jun-1	$250,000	4.75%	4.67%	101.29	$2,009	$252,009
2008-Dec-19	2040-Jun-1	$100,000	4.71%	4.71%	100.00	$0	$100,000
2010-Aug-31	2040-Jun-1	$200,000	4.75%	4.27%	107.96	$10,045	$210,045
2012-Nov-7	2042-Feb-3	$200,000	3.40%	3.22%	103.42	$4,487	$204,487
2013-Feb-20	2042-Feb-3	$200,000	3.40%	3.54%	97.56	-$3,267	$196,733
2013-Oct-2	2045-Jun-2	$400,000	3.90%	3.97%	98.74	-$3,762	$396,238
2014-Jan-10	2045-Jun-2	$200,000	3.90%	3.95%	99.15	-$1,266	$198,734
2014-Mar-6	2054-Mar-5	$100,000	3.75%	3.76%	99.71	-$244	$99,756
2014-May-2	2054-Mar-5	$175,000	3.75%	3.71%	100.89	$1,299	$176,299
2014-Oct-2	2045-Jun-2	$200,000	3.90%	3.43%	108.85	$13,112	$213,112
2015-Feb-5	2045-Jun-2	$200,000	3.90%	2.72%	124.14	$34,954	$234,954
2015-May-26	2046-Dec-2	$200,000	2.75%	3.15%	91.99	-$12,184	$187,816
2015-Oct-15	2046-Dec-2	$200,000	2.75%	3.44%	86.95	-$20,210	$179,790
2016-Jan-19	2046-Dec-2	$200,000	2.75%	3.34%	88.69	-$17,542	$182,458
2016-Jul-12	2046-Dec-2	$150,000	2.75%	2.85%	97.94	-$2,379	$147,621
2016-Oct-13	2046-Dec-2	$200,000	2.75%	3.00%	95.09	-$7,623	$192,377
2017-Jan-17	2048-Jun-2	$200,000	3.30%	3.35%	99.07	-$1,504	$198,496
2017-Aug-17	2054-Mar-5	$150,000	3.75%	3.19%	112.10	$15,560	$165,560
2018-Aug-8	2050-Jun-2	$200,000	3.10%	3.18%	98.46	-$2,603	$197,397
2018-Sep-12	2058-Jun-2	$200,000	2.95%	3.13%	95.89	-$7,328	$192,672
2019-Mar-26	2050-Jun-2	$150,000	3.10%	2.81%	105.92	$7,501	$157,501
2019-Jun-11	2028-Dec-2	$175,000	3.05%	2.34%	105.96	$3,181	$178,181
2020-Jun-22	2030-Jun-2	$100,000	2.20%	1.53%	106.19	$2,715	$102,715
2022-May-9	2052-Dec-2	$180,000	2.80%	4.09%	77.63	-$37,472	$142,528
2022-Jun-23	2052-Dec-2	$300,000	2.80%	4.29%	74.78	-$70,725	$229,275
2022-Nov-4	2031-Jun-2	$350,000	4.18%	4.18%	100.00	$0	$350,000
2023-Jan-18	2062-Jun-2	$120,000	3.80%	3.85%	99.08	-$1,064	$118,936
2023-May-11	2027-Jun-2	$300,000	3.41%	3.41%	100.00	$0	$300,000
2023-Jun-22	2054-Dec-2	$145,000	4.20%	4.28%	98.71	-$1,788	$143,212
2024-Mar-22	2054-Dec-2	$300,000	4.20%	4.41%	96.47	-$10,245	$289,755
2024-Apr-17	2033-Jun-2	$285,000	3.90%	4.50%	95.54	-$10,428	$274,572
2024-Jun-6	2054-Dec-2	$250,000	4.20%	4.32%	98.01	-$4,825	$245,175
2024-Aug-12	2054-Dec-2	$250,000	4.20%	4.23%	99.52	-$1,174	$248,826
2024-Dec-2	2054-Dec-2	$250,000	4.20%	4.10%	101.75	$4,274	$254,274
2025-May-29	2056-Dec-2	$400,000	4.40%	4.48%	98.59	-$5,567	$394,433
2025-Aug-5	2035-Jun-2	$400,000	3.80%	4.03%	98.19	-$6,866	$393,134
2025-Aug-26	2035-Jun-2	$100,000	3.80%	4.11%	97.54	-$2,340	$97,660
2025-Nov-26	2056-Dec-2	$250,000	4.40%	4.43%	99.49	-$1,270	$248,730
2026-Jan-22	2035-Jun-2	$100,000	3.80%	3.82%	99.82	-$180	$99,820
2026-Feb-10	2056-Dec-2	$200,000	4.40%	4.57%	97.25	-$5,497	$194,503
list does not include borrowings to be made after Feb 20, 2026							
Total LTD to Feb 20, 2026:		**$9,830,000**				**-$133,234**	**$9,696,766**
Capital Leases (forecast):							**$944,000**
Total:							**$10,640,766**

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2026 AND 2027 RATE APPLICATION
SRRP INTERROGATORIES

Long-term Debt and Capital Leases
2027-Mar-31

Long-term Borrowings:

Transaction Date	Maturity Date	Par Value	Coupon	All-in Issue Yield	Issue Price	Unamortized Premium	Outstanding Amount
2001-Jul-30	2031-Sep-5	$200,000	6.40%	6.49%	98.86	-$665	$199,335
2003-Jan-8	2031-Sep-5	$100,000	6.40%	5.91%	106.73	$1,898	$101,898
2003-May-6	2033-Sep-5	$100,000	5.80%	5.90%	98.56	-$545	$99,455
2004-Jan-7	2033-Sep-5	$200,000	5.80%	5.68%	101.67	$1,255	$201,255
2004-Sep-28	2035-Sep-5	$200,000	5.60%	5.50%	101.56	$1,410	$201,410
2005-Feb-8	2037-Mar-5	$150,000	5.00%	5.09%	98.65	-$995	$149,005
2005-Apr-29	2037-Mar-5	$150,000	5.00%	5.07%	98.93	-$792	$149,208
2006-Feb-17	2037-Mar-5	$100,000	5.00%	4.71%	104.64	$2,258	$102,258
2007-Feb-27	2040-Jun-1	$100,000	4.75%	4.49%	104.38	$2,524	$102,524
2008-Mar-25	2040-Jun-1	$250,000	4.75%	4.67%	101.29	$1,907	$251,907
2008-Dec-19	2040-Jun-1	$100,000	4.71%	4.71%	100.00	$0	$100,000
2010-Aug-31	2040-Jun-1	$200,000	4.75%	4.27%	107.96	$9,518	$209,518
2012-Nov-7	2042-Feb-3	$200,000	3.40%	3.22%	103.42	$4,266	$204,266
2013-Feb-20	2042-Feb-3	$200,000	3.40%	3.54%	97.56	-$3,110	$196,890
2013-Oct-2	2045-Jun-2	$400,000	3.90%	3.97%	98.74	-$3,629	$396,371
2014-Jan-10	2045-Jun-2	$200,000	3.90%	3.95%	99.15	-$1,221	$198,779
2014-Mar-6	2054-Mar-5	$100,000	3.75%	3.76%	99.71	-$239	$99,761
2014-May-2	2054-Mar-5	$175,000	3.75%	3.71%	100.89	$1,272	$176,272
2014-Oct-2	2045-Jun-2	$200,000	3.90%	3.43%	108.85	$12,620	$212,620
2015-Feb-5	2045-Jun-2	$200,000	3.90%	2.72%	124.14	$33,547	$233,547
2015-May-26	2046-Dec-2	$200,000	2.75%	3.15%	91.99	-$11,759	$188,241
2015-Oct-15	2046-Dec-2	$200,000	2.75%	3.44%	86.95	-$19,527	$180,473
2016-Jan-19	2046-Dec-2	$200,000	2.75%	3.34%	88.69	-$16,943	$183,057
2016-Jul-12	2046-Dec-2	$150,000	2.75%	2.85%	97.94	-$2,293	$147,707
2016-Oct-13	2046-Dec-2	$200,000	2.75%	3.00%	95.09	-$7,353	$192,647
2017-Jan-17	2048-Jun-2	$200,000	3.30%	3.35%	99.07	-$1,458	$198,542
2017-Aug-17	2054-Mar-5	$150,000	3.75%	3.19%	112.10	$15,209	$165,209
2018-Aug-8	2050-Jun-2	$200,000	3.10%	3.18%	98.46	-$2,530	$197,470
2018-Sep-12	2058-Jun-2	$200,000	2.95%	3.13%	95.89	-$7,194	$192,806
2019-Mar-26	2050-Jun-2	$150,000	3.10%	2.81%	105.92	$7,281	$157,281
2019-Jun-11	2028-Dec-2	$175,000	3.05%	2.34%	105.96	$2,014	$177,014
2020-Jun-22	2030-Jun-2	$100,000	2.20%	1.53%	106.19	$2,080	$102,080
2022-May-9	2052-Dec-2	$180,000	2.80%	4.09%	77.63	-$36,679	$143,321
2022-Jun-23	2052-Dec-2	$300,000	2.80%	4.29%	74.78	-$69,273	$230,727
2022-Nov-4	2031-Jun-2	$350,000	4.18%	4.18%	100.00	$0	$350,000
2023-Jan-18	2062-Jun-2	$120,000	3.80%	3.85%	99.08	-$1,051	$118,949
2023-May-11	2027-Jun-2	$300,000	3.41%	3.41%	100.00	$0	$300,000
2023-Jun-22	2054-Dec-2	$145,000	4.20%	4.28%	98.71	-$1,755	$143,245
2024-Mar-22	2054-Dec-2	$300,000	4.20%	4.41%	96.47	-$10,063	$289,937
2024-Apr-17	2033-Jun-2	$285,000	3.90%	4.50%	95.54	-$9,168	$275,832
2024-Jun-6	2054-Dec-2	$250,000	4.20%	4.32%	98.01	-$4,738	$245,262
2024-Aug-12	2054-Dec-2	$250,000	4.20%	4.23%	99.52	-$1,153	$248,847
2024-Dec-2	2054-Dec-2	$250,000	4.20%	4.10%	101.75	$4,194	$254,194
2025-May-29	2056-Dec-2	$400,000	4.40%	4.48%	98.59	-$5,481	$394,519
2025-Aug-5	2035-Jun-2	$400,000	3.80%	4.03%	98.19	-$6,234	$393,766
2025-Aug-26	2035-Jun-2	$100,000	3.80%	4.11%	97.54	-$2,125	$97,875
2025-Nov-26	2056-Dec-2	$250,000	4.40%	4.43%	99.49	-$1,250	$248,750
2026-Jan-22	2035-Jun-2	$100,000	3.80%	3.82%	99.82	-$163	$99,837
2026-Feb-10	2056-Dec-2	$200,000	4.40%	4.57%	97.25	-$5,413	$194,587
list does not include borrowings to be made after Feb 20, 2026							
Total LTD to Feb 20, 2026:		**$9,830,000**				**-$131,544**	**$9,698,456**
Capital Leases (forecast):							**$892,800**
Total:							**$10,591,256**

SRRP Q16 Reference: Finance Charges

a) For each year of the ten most recent actual years please provide a schedule showing the forecasted short-term and long-term interest rates for new debt from the prior year's business plan (i.e. the last business plan prepared before the start of each fiscal year) and the actual average effective short-term and long-term interest rates for new debt.

Response:

	2016	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22	2022-23	2023-24	2024-25
Forecasts:										
Short-term Borrowings	0.80%	0.50%	0.80%	1.60%	2.30%	1.40%	0.50%	0.90%	3.90%	5.00%
Long-term Borrowings	3.10%	3.10%	3.30%	3.70%	3.70%	2.60%	2.20%	3.20%	4.30%	4.90%
Actuals:										
Short-term Borrowings	0.54%	0.53%	0.91%	1.63%	1.68%	0.29%	0.29%	3.39%	4.98%	3.70%
Long-term Borrowings	3.07%	3.09%	3.19%	3.15%	2.56%	1.64%	n/a	4.15%	3.97%	4.29%

Note: the long-term borrowing rate forecast is for a 30-year borrowing, which is SaskPower's preferred long-term borrowing term. However, the province may provide SaskPower with much shorter borrowing terms, based on market conditions and their borrowing plan, which reduces the actual long-term borrowing rate.

SRRP Q17 Reference: Finance Charges

a) Please provide a schedule showing details of the total finance charges for the five most recent actual years and forecasts for 2025/26 through 2026/27 including interest on long-term debt, interest on short-term debt, leases, interest capitalized, debt retirement fund earnings, and other finance charges.

Response:

The following table summarizes actual finance charges for the 2020-21 through 2024-25 fiscal years as well as forecasted finance charges for the 2025-26 through 2026-27 fiscal years.

Finance charges

(in millions)	Actual **2020-21**	Actual **2021-22**	Actual **2022-23**	Actual **2023-24**	Actual **2024-25**	Forecast **2025-26**	Forecast **2026-27**
Interest on long-term debt	$ 296	$ 284	$ 270	$ 286	$ 326	$ 363	$ 387
Interest on lease liabilities	149	136	141	132	131	129	123
Interest on short-term advances	4	1	20	33	27	24	37
Interest on employee benefit plans	10	8	4	8	6	5	5
Interest on provisions	6	7	8	11	14	25	19
Interest capitalized	(10)	(16)	(30)	(39)	(47)	(48)	(70)
Amortization of debt premiums/discounts	(5)	(6)	(4)	(3)	-	1	4
Amortization of bond forward agreements	-	1	1	-	-	-	-
Other interest and charges	1	1	1	1	1	1	1
Finance expense	**451**	**416**	**411**	**429**	**458**	**500**	**506**
Debt retirement fund earnings	(21)	(15)	(8)	(14)	(32)	(32)	(42)
Debt retirement fund realized market value gains	(2)	1	7	-	-	-	-
Interest income	(2)	(1)	(4)	(6)	(8)	(5)	(6)
Finance income	**(25)**	**(15)**	**(5)**	**(20)**	**(40)**	**(37)**	**(48)**
TOTAL FINANCE CHARGES	**$ 426**	**$ 401**	**$ 406**	**$ 409**	**$ 418**	**$ 463**	**$ 458**

SRRP Q18 Reference: Finance Charges

a) SaskPower states on page 28 of the application that it contributes at least 1% of the face value of certain outstanding debts annually to debt retirements funds administered by the Government of Saskatchewan. Please:

i. Explain which debts have debt retirement funds associated with them.

ii. Describe any circumstances where SaskPower contributes more than 1% of the face value.

iii. Explain whether or not the Government of Saskatchewan requires the debt retirement funds through legislation or policy and if so, provide a copy of the relevant legislation or policy.

iv. Provide details of the actual and forecasted debt retirement fund balances, earnings, contributions and average returns for the five most recent actual years and forecasts for 2025-26 through 2026-27.

b) Has SaskPower updated the analysis conducted in February 2020 described in the response to first round interrogatory SRRP-Q18 (b) from the 2022 and 2023 rate application? If so, please provide a summary of the updated analysis.

Response:

a)

i. Province of Saskatchewan debt when first issued in the market having a term of 10 years or greater has a debt retirement fund.

ii. This has not occurred

iii. Debt retirement funds are required based on the province's long-standing approach in managing its debt portfolio. It is not a legislated requirement and there is no formal policy in place.

iv.

	2020-21 (actual)	2021-22 (actual)	2022-23 (actual)	2023-24 (actual)	2024-25 (actual)	2025-26 (forecast)	2026-27 (budget)
Debt Retirement Fund Schedule (millions):							
Opening	847.6	864.4	738.3	717.6	799.7	930.8	983.6
Earnings	23.2	13.9	1.0	14.4	32.1	31.5	42.0
Market Value Gains (Losses)	-26.8	-39.6	-10.0	-2.3	24.6	-5.0	0.0
Instalments	62.8	62.5	60.1	70.0	74.4	84.8	95.8
Redemptions	-42.4	-162.9	-71.8	0.0	0.0	-58.5	0.0
Closing	864.4	738.3	717.6	799.7	930.8	983.6	1,121.4
Debt Retirement Fund Returns:							
Actual Unit Price-Based Return:							
Opening Unit Price	$1,291.28	$1,286.32	$1,244.35	$1,231.79	$1,250.28		
Closing Unit Price	$1,286.32	$1,244.35	$1,231.79	$1,250.28	$1,334.49		
Unit Price Change	-$4.96	-$41.97	-$12.56	$18.49	$84.21		
Return	-0.38%	-3.26%	-1.01%	1.50%	6.74%		
Forecast Return (Based on Business Plan):						2.77%	3.99%

b) No update has been completed.

SRRP Q19 Reference: Depreciation and MFR Tab 8

a) Please confirm that the most recent external depreciation study is from 2023 and provide the proposed timing for the next external depreciation study.

b) Would SaskPower consider commissioning a version of the next external depreciation study that could be made public?

c) Did SaskPower accept and implement all of the proposed changes to average service life estimates recommended by the external consultant? If not, please explain which recommendations were not accepted and why.

d) With reference to the statement on page 1 of the rate application that states "SaskPower is continuing its work on extending the life of up to 1,530 MW of existing coal-fired generation assets by 25 years, eliminating the significant capital investment needed to construct new natural gas generation facilities over the same horizon", please discuss whether SaskPower has reflected any impacts of the coal generation life extensions on the current depreciation rates for the existing coal units. If yes, please describe any adjustment and quantify the impact on depreciation expense. If not, please explain why not.

e) With respect to the table on page 27 of the application, please provide an explanation for the $51 million in "amortization of right-of-use assets" including a list of the right-of-use assets.

f) Please provide a table that quantifies the impact of any and all changes SaskPower has made to its depreciation rates by depreciable property group since the time of the last rate application.

g) Please discuss whether or not SaskPower's current depreciation rates include a provision to true-up or amortize variances between booked depreciation and forecast depreciation at proposed depreciation rates?

h) Please describe SaskPower's process for reviewing and revising its depreciation rates between external depreciation studies.

Response:

a) It is recommended that a formal depreciation study be completed every five years. An external consultant was engaged to complete the 2022-23 depreciation study and it is planned to complete another external review in 2027-2028.

b) SaskPower will investigate, with the successful external consultant, the possibility of preparing a report that can be made public.
c) Yes, all changes recommended by the external consultant have been implemented.
d) SaskPower has not reflected any impacts of the coal generation life extensions on the current depreciation rates for the existing coal units. A new supply plan was approved by the Board in November 2025. Management is in the process of assessing the impacts of extending the operational life of the conventional coal-fired units, therefore the depreciation rates for these units have not been adjusted to align with the new supply plan.
e) Right-of-use assets are amortized over the term of each of the right-of-use lease contracts. Right-of-use contracts include Purchase Power Agreements related to natural gas-fired facilities (Meridian Cogeneration Station, Spy Hill Generating Station and the North Battleford Generating Station) where SaskPower has the exclusive right to the use of production. Also included are land and building leases with a term greater than one year.
f)

Depreciable Property Group	**Estimated Annual Impact (000's)**			
	2021-22	**2022-23**	**2023-24**	**2024-25**
Power Production				
Coal	$ 1,231	$ (4,266)	$ 7,251	
Gas	(791)		(558)	$ 1,222
Hydro	477	(323)		804
Other		(107)		
Meters			(909)	
Tools		1,289		
	$ 917	**$ (3,407)**	**$ 5,784**	**$ 2,026**

g) SaskPower's policy is to calculate depreciation on a straight-line basis over the estimated average service life (ASL) of the asset. In cases where a generation unit is expected to be retired in the near future, all of the components that make up the generating unit are given the same useful life. This is done to ensure all components of that generating unit are fully amortized by the expected retirement date of the facility. The depreciation rate is calculated by dividing the net book value of the unit over its remaining useful life. This analysis is completed annually as part of the depreciation study. The updates are implemented prospectively affecting future periods.

h) On an annual basis, SaskPower's Finance Department reviews the depreciation rates with internal personnel from various operating areas to determine whether any changes to the estimated useful lives are required based on manufacturers' guidance, past experience and future expectations regarding the potential for technical obsolescence.

SRRP Q20 Reference: Decommissioning and Disposal of Assets

a) Please discuss how SaskPower plans for the decommissioning and disposal of assets, in particular generation assets.

b) Are decommissioning requirements considered when selecting new generation resources? Please discuss.

c) Please discuss how SaskPower addresses refurbishment, reuse, or recycling of materials during decommissioning. In particular, are some types of generation assets more easily reused or recycled than other types of generation assets?

d) Please discuss SaskPower's approach to interim and terminal net salvage costs and provide a copy of the relevant accounting policy.

Response:

a)

SaskPower has a minimum 10-year cycle to review all decommissioning and reclamation plans for the generation facilities excluding the hydroelectric facilities as they are assumed to remain in service indefinitely. In conjunction with this, effective January 1st, 2020, the Ministry of Environment (MEnv) brought in regulations stating that all facilities that have an Industrial Waste Work (IWW) permit associated with the facility require a Decommissioning and Reclamation (D&R) plan be submitted and approved by the MEnv. The D&R plans are to be reviewed and updated at a minimum of every 5 years or sooner if warranted by major changes to the facility and operations. SaskPower has received approval from the MEnv for D&R plans for six generation sites that require an IWW permit (Chinook, Queen Elizabeth, Boundary Dam, Shand, Poplar River Power Station and Cory Cogeneration).

The six D&R Plans, required under the IWW Permit to Operate 5 year review cycle, were updated in 2024 and approved by the MEnv in 2025. Through this review, the D&R Plans were refined to better understand SaskPower's decommissioning obligations and liability costs. The environmental reclamation costs are anticipated to be one of the larger risks to the cost estimates for the decommissioning and reclamation plan and have been included in the D&R Plans as a contingency, with further work being carried out to further refine the costs associated with this occurring in 2026-2028. SaskPower will continue to monitor and manage site conditions and possible contamination through work required under the existing IWW permit.

Nearer to the time of decommissioning, SaskPower will undertake additional site assessment activities to refine the remedial planning for the facility. Additional options for ongoing assessment and delineation will be explored in the interim.

D&R plans for the non-IWW sites, which operate on a 10-year review cycle, are in the process of being reviewed and updated throughout 2025 and 2026.

The estimated cost used to define the required Asset Retirement Obligation (ARO) funding is a class 4 estimate per ASTM E2516-11 Standard Classification for Cost Estimate Classification System. In cases where the actual retirement of an asset is approaching, a class 3 estimate per ASTM E2516-11 Standard Classification for Cost Estimate Classification System will be undertaken and is required by MEnv 12 months prior to retirement.

b)

Decommissioning requirements are considered from a cost and risk perspective. Cost assessment includes inputs of total capital cost, annual cash flow percentages, construction time, interest rates and discount rates which results in outputs of the required annual expenditures and the salvage value at the end of the study period. Project approvals are made in consideration of a risk assessment, risk and the ability to mitigate risk play a role in in the decision to proceed for projects that require special consideration upon decommissioning.

c)

SaskPower addresses each generating station on a case-by-case basis to determine what building materials and equipment will be scrapped (metal and copper recycling) or salvaged (retained for resale or kept as spares for another generating station). Scrap materials will generally comprise of all steel building structures, tin siding and roofing from buildings, copper electrical cables, steel and copper piping and other scrapped metal equipment from within the power plant and other buildings at site. These scrapped materials will be hauled to the nearest metal recycler and SaskPower will be reimbursed based on scrap weight and the current market price for scrap metal. At the onset of the decommissioning and reclamation execution, equipment is reviewed to determine if it has salvage value, either resale or to be retained as a spare at another SaskPower generating station. Typically, transformers will be the most common piece of equipment which would have salvage value to SaskPower since they are a more generic type of equipment which can be used in numerous applications. Equipment such as pumps, fans, and compressors may be salvageable, but not likely since they are designed and sized for more specific applications within the generating station. Turbines and generators are highly unlikely to have any salvage value since they will be old technology, at the end of their useful life at the time of decommissioning and may have some unique/specific designs to suit a given generating station. Regardless of the type of equipment, age and condition will be a determining factor in deciding whether a piece of equipment is salvageable.

d)

SaskPower has established provisions for the gross terminal costs, excluding potential salvage value of equipment, of decommission coal, natural gas, cogeneration, wind generation facilities and other properties.

2026 AND 2027 RATE APPLICATION
SRRP INTERROGATORIES

Accounting Policy:

Provisions

A provision is recognized if, as a result of a past event, the Corporation has a present legal or constructive obligation that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation, the timing or amount of which is uncertain. Provisions are determined by discounting the expected future cash flows at a rate that reflects current market assessments of the time value of money and the risks specific to the obligation. For SaskPower, that rate is considered to be equal to the spot rate derived from yields on Government of Saskatchewan bonds using a rate term that matches the timing of the expected cash flows. The unwinding of the discount on provisions is recognized in profit or loss as finance expense.

Decommissioning

A decommissioning provision is a legal or constructive obligation associated with the decommissioning of a long-lived asset. The Corporation recognizes decommissioning provisions in the period they are incurred if a reasonable estimate of fair value (net present value) can be determined. The Corporation recognizes provisions to decommission coal, natural gas, cogeneration, wind generation facilities and other properties typically in the period in which the facility is commissioned.

The fair value of the estimated decommissioning costs is recorded as a provision with an offsetting amount capitalized and included as part of property, plant and equipment. The provisions are increased periodically for the passage of time by calculating interest expense. The offsetting capitalized asset retirement costs are depreciated over the estimated useful life of the related asset. The calculations of fair value are based on detailed studies that take into account various assumptions regarding the anticipated future cash flows including the method and timing of decommissioning and estimates of future inflation rates. Decommissioning provisions are periodically reviewed and any changes in the estimated timing and amount of future cash flows, as well as changes in the discount rate, are recognized as an increase or decrease in the carrying amount of the obligation and the related asset. If the asset value is fully depreciated the changes are recognized in profit or loss as other expenses.

SRRP Q21 Reference: Export Revenues and Electricity Trading

a) Please discuss whether SaskPower's export revenues shown on page 22 of the application include any electricity trading activities and if so, quantify the electricity trading revenues.

b) Please describe the types of export sales (long-term contract, short-term contract, spot market sales) SaskPower makes and provide details of SaskPower's current export transmission rights.

c) Please describe in detail how SaskPower prepares its export revenue forecasts and provide an explanation for the change in export revenues in 2025/26 relative to 2023/24 and 2024/25 actuals.

d) Please provide SaskPower's actual export sales for the last 10 years compared to forecasts from the prior year's business plan (i.e. the last business plan prepared prior to the start of the fiscal year) and discuss the reasons for any variances.

e) SaskPower states at page 22 of the application that electricity capacity in Alberta has increased and lower export prices are expected going forward. Please provide a summary of the proportion of SaskPower's export sales to Alberta compared to other jurisdictions in terms of both volume and revenue for the last 5 actual years.

f) With reference to page 32 and Figure 30 of the Alberta Electric System Operator (AESO) 2024 Annual Market Statistics Report available at: https://www.aeso.ca/assets/Uploads/market-and-system-reporting/Annual-Market-Stats-2024.pdf

   Please discuss the nature and cause of the extended outage that reduced interchange utilization between Saskatchewan and Alberta to zero for 49% of the year.

Response:

a) The export revenues shown on page 22 of the application do not include any electricity trading activities. There were no electricity trading activities in the 2023-24 through 2024-25 fiscal years.

b) SaskPower participates in several organized deregulated markets. The organized markets are called Independent System Operators ("ISO") or Regional Transmission Organizations ("RTO"):

ISO
Alberta Electric System Operator ("AESO") - Alberta

RTO
Southwest Power Pool ("SPP") - Midwestern US including North and South Dakota
Midcontinent Independent System Operator ("MISO") – Midwestern states and provinces including Manitoba and Minnesota.

SaskPower may also engage in bi-lateral transactions with counterparties in the AESO, MISO and SPP footprints.

SaskPower's export sales are almost always spot market transactions, but SaskPower has occasionally entered single month export transactions. As at February 2026, SaskPower has not entered into any short-term or long-term export contracts.

SaskPower has firm transmission rights on export paths within Saskatchewan:

1. 153 MW to AESO
2. 150 MW to SPP (US)
3. 125 MW to Manitoba

c) SaskPower's export revenue forecast is prepared in conjunction with the development of the annual Fuel and Purchased Power budget. SaskPower uses an optimized dispatch model to forecast fuel and purchased power costs, accounting for a variety of factors including system load, import requirements, and commodity prices. The model initiates export transactions where energy is available and projected market conditions indicate profit potential.

The change in export revenues in 2025-26 relative to 2023-24 and 2024-25 is attributable to higher average export prices in 2023-24 ($169/MWh) followed by a significant drop in 2024-25 ($64/MWh) before finally settling at $62/MWh in 2025-26. This drop in average export price is largely attributable to increased supply and new regulations in Alberta. In addition, export volumes also fluctuated from 763 GWh in 2023-24 to 438 GWh in 2024-25 as the transmission intertie connecting Alberta and Saskatchewan was unavailable for the latter portion of the year due to a failure on Alberta's portion of the line. Forecasted export volumes recovered to 840 GWh in 2025-26, as the transmission intertie was repaired in October 2025.

The export revenue forecast methodology is designed to project the revenues for export of electrical energy generated within Saskatchewan while the electricity trading revenue forecast methodology is designed to project the revenues created from proprietary trading transactions performed by NorthPoint.

d) The below outlines SaskPower's actual export sales for the last 10 years compared to forecast from the prior year's business plan.

Export Sales

(in millions)	**Actual**	**Budget**
2024-25	$ 28	$ 95
2023-24	129	64
2022-23	139	44
2021-22	77	21
2020-21	54	28
2019-20	21	32
2018-19	30	12
2017-18	10	10
2016-17	5	17
2015-16*	9	21

* 15 month period (fiscal year-end changed from December to March)

2024-25: Exports were $67 million under budget due to lower sales volumes of 611 GWh and an average price approximately $26/MWh lower than budgeted. These decreases were largely due to reduced sales volumes resulting from the unavailability of the transmission intertie connecting Alberta and Saskatchewan for the latter portion of the year due to a failure on Alberta's portion of the line.

2023-24: Exports were $65 million over budget due to an average price approximately $96/MWh higher than budgeted, offset by lower sales volumes of 114 GWh.

2022-23: Exports were $95 million over budget due to an average price approximately $62/MWh higher than budgeted and an increase in sales volumes of 429 GWh.

2021-22: Exports were $56 million higher than budget due to an average price approximately $46/MWh higher than budget, along with a 369 GWh increase in sales volumes.

2020-21: Exports were $26 million over budget due to an average price approximately $52/MWh higher than expected, partially offset by sales volumes that were 28 GWh lower than budgeted.

2019-20: Exports were $11 million under budget due to lower sales volumes of 167 GWh due to the Saskatchewan/Alberta intertie line being down for maintenance from June through August, partially offset by an average price that was $6/MWh higher than expected.

2018-19: Exports were $18 million over budget due to an average price that was approximately $17/MWh higher than expected and sales volumes that were 207 GWh higher than budgeted.

2017-18: No material variance.

2016-17: Exports were $12 million lower than budget due to an average price approximately $32/MWh lower than budget, along with lower sales volumes of 96 GWh.

2015-16: Exports were $12 million under budget due to sales volumes that were 230 GWh lower than expected, partially offset by an average export price that was $22/MWh higher than budgeted.

e) The below outlines SaskPower's export sales to Alberta compared to other jurisdictions for both volumes and revenue for the last 5 years of actuals.

Exports by Market

(in MWhs)	Actual **2020-21**	Actual **2021-22**	Actual **2022-23**	Actual **2023-24**	Actual **2024-25**
Alberta	424,277	627,894	721,296	422,318	160,095
Manitoba	427	183	790	1,936	2,740
Foreign	101,711	67,085	210,424	338,732	274,786
	526,415	695,162	932,510	762,986	437,621

(in thousands)	Actual **2020-21**	Actual **2021-22**	Actual **2022-23**	Actual **2023-24**	Actual **2024-25**
Alberta	$ 36,321	$ 71,926	$120,417	$ 61,980	$ 12,558
Manitoba	12	11	59	73	63
Foreign	17,806	4,737	18,074	66,816	15,534
	54,139	76,673	138,550	128,869	28,156

f) For power to flow from Saskatchewan to Alberta, a converter station is required to synchronize electricity between the two provinces- the McNeill Converter Station. This station is owned by ATCO Power and is relatively aged. The extended outage in 2024 was due to maintenance activities at this facility.

SRRP Q22 Reference: Other Revenue

a) Please explain how SaskPower forecasts customer contribution revenues in the test years and provide an explanation for the difference in forecasted contributions between 2025/26 and 2026/27.

Response:

Customer contributions are funds received from certain customers toward the cost of service extensions. These contributions are recognized immediately in profit or loss as other revenue when SaskPower's contractual obligations are met and the related property, plant and equipment is available for use.

Forecasted distribution customer connects are based on historic averages of actual customer contribution revenue received by SaskPower with consideration given to forecasted load growth.

Forecasted transmission customer connects are based on a combination of:

- Forecasted capital projects for which customers or independent power producers are responsible to pay for a portion of the costs;
- Meetings with Key Account Managers regarding updates received from customers on any anticipated changes in their short- and long-term energy requirements (this includes expansions or speculative load); and
- Historic averages of actual customer contribution revenue received by SaskPower.

The difference in forecasted contributions between 2025-26 and 2026-27 relates to the expected completion of various large transmission projects.

SRRP Q23 Reference: Other Revenue

a) Please discuss how the CO2 sales revenue forecasts are prepared.

b) Please provide an explanation for the reduction in CO2 sales revenues from 2023-24 ($26 million) to 2024-25 ($19 million).

Response:

A. CO_2 sales revenue forecasts are prepared in accordance with contractual obligations of the off taker. The forecast does not assume SaskPower captures and sells the maximum amount of CO_2 and factors in average expected facility availability targets.

B. The reduction in CO_2 sales revenue from 2023-24 to 2024-25 was primarily the result of an arbitration settlement.

SRRP Q24 Reference: Other Revenue

a) Please provide a detailed breakout of Miscellaneous Revenue for the five most recent actual years and forecasts for 2025/26 and 2026/27. Please provide an explanation for the decreased revenue in 2025/26 and 2026/27 compared to 2024/25.

Response:

The following table summarizes actual Miscellaneous Revenue for the 2020-21 through 2024-25 fiscal years as well as forecasted amounts for the 2025-26 and 2026-27 fiscal years.

Other Revenue

(in millions)	Actual **2020-21**	Actual **2021-22**	Actual **2022-23**	Actual **2023-24**	Actual **2024-25**	Forecast **2025-26**	Forecast **2026-27**
Late payment charges	$ 4	$ 7	$ 8	$ 7	$ 7	$ 7	$ 6
Joint use charge	5	6	4	6	6	7	7
Connect fees	2	2	2	2	1	1	1
Meter reading	2	2	2	2	3	2	3
Custom work	3	3	4	4	5	4	5
Trans tariff revenue - external	-	1	1	2	2	1	1
Gas & electrical inspections*	13	-	-	-	-	-	-
Other revenue	2	2	3	2	2	2	2
Green power premium	-	-	-	1	1	-	-
Renewable energy credits	-	2	1	1	-	-	-
Flyash	8	11	11	11	12	12	12
TOTAL MISCELLANEOUS REVENUE	**$ 39**	**$ 36**	**$ 36**	**$ 38**	**$ 39**	**$ 36**	**$ 37**

* Provincial cabinet approved the transfer of the Corporation's Gas and Electrical Inspections (GEIS) Division to the Technical Safety Authority of Saskatchewan (TSASK) effective January 31, 2021.

The decrease in revenue in 2025-26 and 2026-27 compared to 2024-25 is mainly due to decreased monthly rates on meter reading, the termination of the green power premium program, custom work trending lower, and reduced external transmission use.

SRRP Q25 Reference: Business Plan

a) Please provide a description of SaskPower's annual business planning cycle including inputs required, review and approval processes, and the typical timing of internal and external updates.

Response:

The following is a summary of SaskPower's typical business planning cycle:

April to June (Q1)

- The Q1 load forecast is finalized, and the Supply Plan is updated to reflect new load forecast assumptions.
- Detailed capital plans are updated, preliminary capital targets and OM&A budgets are prepared, and new initiative requests or funding shortfalls are identified. Revisions to the capital plan and OM&A budget are guided by load forecasts, asset management programs, supply plans, regulatory changes, public policy initiatives, and inflationary factors.
- Preliminary revenue and expense budgets are developed.
- Rate increase scenarios are developed based on preliminary targets and budgets.
- SaskPower's Audit & Finance Committee and Board of Directors review and approve the Rate Strategy for use in the Business Plan and Rate Application.

July to September (Q2)

- Detailed capital plans are updated, and any additional new initiative requests or funding shortfalls are prioritized by SaskPower's Executive.
- Revenue and expenses are updated to reflect any changes in assumptions (i.e., natural gas prices).
- All other preliminary budget assumptions used in developing the rate strategy are reviewed and revised where necessary.
- SaskPower's Executive reviews and provides feedback on the preliminary Business Plan.

October to December (Q3)

- The preliminary Business Plan is updated to incorporate the most recent current year forecast as well as the Executive's feedback during the preliminary review.
- SaskPower's Executive and Audit & Finance Committee review and approve the Business Plan.
- Business Units update detailed capital plans based on the approved capital targets.
- SaskPower's Board of Directors reviews and approves the Business Plan, which is subsequently provided to the Crown Investments Corporation (CIC).

January to March (Q4)

- Crown Investments Corporation of Saskatchewan reviews and approves SaskPower's Business Plan.
- The Government of Saskatchewan Ministry of Finance consolidates SaskPower's financial results as part of the Province's financial reporting package.

SRRP Q26 Reference: Generation expense

For each of the last three actuals years, plus forecasts for 2025/26 through 2026/27, please provide the total cost of generation for each fuel source (e.g. coals, natural gas, etc) broken out into:

i. Fuel and purchased power expense
ii. Operations and maintenance expense
iii. Federal carbon charges
iv. Finance charges
v. Depreciation expenses
vi. Taxes
vii. Other

Response:

The following table summarizes generation expense actuals broken down by fuel source for the 2022-23 through 2024-25 fiscal years as well as forecasted amounts for the 2025-26 through 2026-27 fiscal years.

Generation Expense

(in millions)	Actual **2022-23**	Actual **2023-24**	Actual **2024-25**	Forecast **2025-26**	Forecast **2026-27**
Natural Gas	$ 324	$ 253	$ 224	$ 240	$ 264
Coal	318	296	313	311	353
Hydro	20	16	18	18	24
PPAs & Imports	411	338	338	369	430
Other	50	50	42	51	51
Clean Electricity Transition Grant	-	-	(136)	(161)	-
Fuel and purchased power	1,123	953	799	828	1,122
Natural Gas	24	28	37	67	-
Coal	186	242	241	299	-
PPAs	-	(1)	2	2	-
Federal carbon charge	210	269	280	368	-
Natural Gas	56	60	66	86	90
Coal	160	163	180	187	184
Hydro	19	19	23	23	26
PPAs	11	13	13	19	19
Wind	8	6	6	7	7
Operating, maintenance and administration[1]	254	261	288	322	326
Natural Gas	88	85	93	118	135
Coal	139	136	147	134	133
Hydro	21	21	22	23	25
PPAs	48	48	49	49	49
Wind	8	8	8	7	7
Depreciation	304	298	319	331	349
Finance charges[2]	120	128	147	165	167
Taxes[2]	24	25	29	31	33
Other expenses[1]	8	5	10	36	37
Total generation expense	**$ 2,043**	**$ 1,939**	**$ 1,872**	**$ 2,081**	**$ 2,034**

1. The expenses presented in the above table exclude shared costs that cannot be directly allocated to generation activities (i.e., costs for supporting business units such as human resources and safety, finance, legal etc.) OM&A consists of business unit costs for generation and purchased power agreements; and other expenses includes amounts related to losses on asset retirements and costs of disposals.

2. Finance charges and taxes (corporate capital tax) have been calculated based on the relative proportion of the asset acquisition value.

SRRP Q27 Reference: Fuel and Purchased Power (F&PP)

a) Please discuss if there have been any changes to the methods SaskPower uses to prepare its fuel and purchased power forecasts since the response to SRRP Round 1 question 29 from the 2022 and 2023 rate application. If so, please explain any changes.

b) Please provide a table showing the total GWh of generation for each of the last three actual years plus forecasts for 2025-26 and 2026-27 for:

i. SaskPower's own generation
ii. Purchased power within Saskatchewan
iii. Imports from outside Saskatchewan

Response:

a) There have been no material changes to the methodology employed since the response to SRRP Round 1 question 29 from the 2022 and 2023 rate application.

b) The following table summarizes total actual generation supplied (in GWh) for 2022-23 through 2024-25 and forecasted generation for 2025-26 through 2026-27:

Fuel and purchased power - generation supplied

(in GWh)	Actual **2022-23**	Actual **2023-24**	Actual **2024-25**	Forecast **2025-26**	Forecast **2026-27**
SaskPower-owned generation	18,618	18,480	17,891	18,551	19,440
Purchased power within Saskatchewan	6,030	6,094	6,382	6,649	7,008
Imports from outside Saskatchewan	1,778	2,001	1,901	1,841	1,924
Gross electricity supplied	**26,426**	**26,575**	**26,174**	**27,040**	**28,372**

SRRP Q28 Reference: Fuel and Purchased Power (F&PP)

a) Please identify any actual or forecast energy volumes subject to "Take or Pay" (TOP) obligations under the PPAs (in total) for each of the three most recent actual years and forecasts for 2025-26 and 2026-27.

b) Please discuss whether SPC has been required to pay for unused energy because of TOP provisions and indicate whether any such costs are forecast to be incurred in the three most recent actual years.

Response:

a) All of SaskPower's PPAs are subject to Take or Pay obligations for SaskPower.

PPA energy volumes

(in GWh)	Actual **2022-23**	Actual **2023-24**	Actual **2024-25**	Forecast **2025-26**	Forecast **2026-27**
Energy volumes	7,713	7,989	8,218	8,452	8,513

b) There are circumstances where SaskPower may need to pay for energy rather than receive it, for system security reasons. These decisions are made by SaskPower and not the Independent Power Producer (IPP) and are further defined by each of the respective PPAs.

SRRP Q29 Reference: Fuel and Purchased Power (F&PP)

a) To the extent possible without requiring the disclosure of confidential information, please provide the most recent actual annual and forecast for the test years average power price for generation owned by SPC and separately, the average purchase price for PPAs by fuel type, and explain any differences in unit costs.

Response:

The following table summarizes actual unit costs for each applicable fuel type for Power Purchase Agreements (PPAs) and SaskPower for the 2024-25 fiscal year as well as forecasted amounts for 2025-26 through 2026-27.

The fuel cost for PPA gas-fired generation is lower than SaskPower's gas-fired fleet because one of the major PPA units is a fuel-efficient cogeneration facility and two other PPA units use a relatively new technology, which is more efficient than the older units in SaskPower's fleet.

The fuel cost for wind PPAs is higher than SaskPower's wind because the PPA price includes capital recovery and O&M costs. SaskPower's fuel price for wind is $0. The non-fuel component costs are captured in OM&A and capital-related expenses.

SaskPower does not have any PPAs with coal facilities; however, it does have long-term import PPA agreements with Manitoba Hydro.

The PPA "Other" category includes green technologies, such as heat recovery, flare gas, and landfill gas-fired generation. SaskPower does not have any comparable facilities.

Fuel and purchased power - generation supplied

	Actual	Forecast	Forecast			Actual	Forecast	Forecast
$/MWh	2024-25	2025-26	2026-27		$/MWh	2024-25	2025-26	2026-27
SaskPower					**PPA's**			
Gas	$ 27				Gas	$ 16		
Coal	$ 50				Coal	N/A	N/A	N/A
Wind	$ -				Wind	$ 54		
Imports	N/A	N/A	N/A		Imports	$ 88		
Hydro	$ 6				Hydro	N/A	N/A	N/A
Solar	N/A	N/A	N/A		Solar	$ 86		
Other	N/A	N/A	N/A		Other	$ 95		

SRRP Q30 Reference: Natural Gas

a) Please describe SaskPower's natural gas procurement processes including details on any firm contracted transmission and/or storage volumes for the three most recent actual years and forecasts for 2025-26 through 2026-27.

Response:

This response contains confidential information and cannot be released publicly. However, a full response has been provided to the Saskatchewan Rate Review Panel for their review.

SRRP Q31 Reference: Natural Gas

a) Please describe any changes to SaskPower's procedures, Risk Management Policies, and/or Risk Management Manuals related to procurement and pricing of Natural Gas supplies, including Storage and hedging since the last rate application.

Response:

There have been no changes since the last rate application.

SRRP Q32 Reference: Natural Gas

a) Please provide a table showing natural gas purchases within Saskatchewan and outside Saskatchewan including total volumes, average unit costs, and total natural gas expenses for each of the three most recent actual years and forecasts for 2025/26 through 2026/27.

Response:

	Gas Purchased in Saskatchewan			Gas Purchased Outside Saskatchewan		
Fiscal Year	**Volume (Million GJs)**	**Total Cost ($ Millions)**	**$/GJ**	**Volume (Million GJs)**	**Total Cost ($ Millions)**	**$/GJ**
2022-23	11	59	$ 5.24	47	211	$ 4.46
2023-24	13	36	$ 2.78	59	173	$ 2.92
2024-25	16	29	$ 1.80	61	140	$ 2.30
2025-26*	13	47	$ 3.57	52	97	$ 1.85
2026-27*	12	42	$ 3.52	48	70	$ 1.47

*** Forecasted volume and cost**

SRRP Q33 Reference: Natural Gas

a) Please provide a schedule showing actual natural gas hedged volumes for the five most recent actual years and currently hedged volumes for 2025/26 through 2026/27. Please summarize the types of financial instruments used each year and indicate the overall annual cost of hedged volumes in aggregate and on a unit basis.

b) Please provide an estimate of the impact of SaskPower's hedging activities on natural gas costs for each of the five most recent actual years. Please also provide a discussion on the net cost or benefit to ratepayers of the hedging program over the past five years.

Response:

a) The following schedule shows the total physical and financial fixed-price transactions by fiscal year:

	Physical Hedges			Financial Hedges (Swaps)		
Fiscal Yeai	GJ	Value	$/GJ	GJ	Value	$/GJ
2020/21	27	$ 100	$ 3.74	14	$ 49	$ 3.43
2021/22	23	$ 89	$ 3.83	13	$ 45	$ 3.45
2022/23	21	$ 81	$ 3.97	12	$ 45	$ 3.78
2023/24	27	$ 97	$ 3.66	15	$ 57	$ 3.84
2024/25	29	$ 94	$ 3.28	16	$ 52	$ 3.25
2025/26	30	$ 93	$ 3.08	17	$ 54	$ 3.14
2026/27	27	$ 83	$ 3.04	15	$ 47	$ 3.09

b) When benchmarked against settled market prices over the five most recent actual years, the net impact of these transactions reflects an opportunity cost of approximately $157 million, representing the net cost relative to what could have been realized in prevailing market conditions.

Fiscal Year	GJ (Millions)	Notional Value (Millions)
2020/21	41	$54
2021/22	36	-$3
2022/23	32	-$42
2023/24	41	$62
2024/25	45	$86
Total	**196**	**$157**

SaskPower's natural gas hedging program is a key component of the corporation's approach to managing fuel price risk and ensuring security of supply. The volumes secured through the program cover approximately half of SaskPower's annual natural gas requirements, providing a prudent balance between cost certainty and market flexibility. This approach supports reliable operations while avoiding over-exposure to any single market outcome.

By fixing a portion of its natural gas costs in advance, SaskPower limits the share of its fuel portfolio that is exposed to short-term market price volatility. This reduces variability in fuel expenses and helps moderate fluctuations in SaskPower's net income. The intent of the hedging program is not to forecast natural gas prices or consistently achieve the lowest possible cost, but rather to manage risk and improve predictability in an inherently volatile commodity market. This is consistent with SaskPower's mandate as a regulated electric utility to operate in a financially stable and disciplined manner.

In periods of declining natural gas prices, hedge settlements can result in negative values, reflecting the difference between fixed hedge prices and lower prevailing market prices. These outcomes represent an opportunity cost rather than an economic loss to SaskPower. Importantly, any negative settlement value on hedged volumes is offset by the benefit realized on unhedged volumes, which are purchased at lower market prices.

It is therefore not appropriate to evaluate hedge performance on a transaction-by-transaction basis. The effectiveness of SaskPower's hedging strategy must be assessed across the full natural gas portfolio and over time. By intentionally hedging only a portion of forecasted demand, SaskPower balances protection against adverse price spikes with the ability to benefit from favorable market conditions. This disciplined approach reduces the risk of extreme outcomes while preserving flexibility.

Beyond financial results, SaskPower's natural gas hedging program contributes to more stable electricity costs for customers by reducing volatility in fuel inputs. Lower variability in fuel costs helps limit sudden cost pressures and supports more predictable rate outcomes. In addition, reduced earnings and cash flow volatility strengthens SaskPower's overall financial resilience and supports long-term planning.

Overall, SaskPower's natural gas hedging program provides value by managing exposure to commodity price volatility, improving cost certainty, and supporting stable financial and customer outcomes. While individual hedge settlements may appear unfavorable under certain market conditions, the program's value is realized when outcomes are evaluated on a portfolio basis and over the full market cycle, consistent with its role as a risk management—not speculative—strategy.

2026 AND 2027 RATE APPLICATION
SRRP INTERROGATORIES

SRRP Q34 Reference: Natural Gas

a) Please provide a schedule that shows SaskPower's natural gas fuel efficiency ratio (i.e. the kW.h generated per unit of natural gas) for each of the three most recent actual years and forecasts for 2025-26 and 2026-27. Please comment on any material variances between years.

b) Please discuss if the fuel efficiency ratios vary materially across plants and if so, why?

c) Please describe how SaskPower prepares its forecasts of natural gas fuel efficiencies.

Response:

a) SaskPower Natural Gas Fuel Efficiency Ratio:

Fiscal Year	MWh/GJ
2022/23	0.112
2023/24	0.111
2024/25	0.118
2025/26	0.193
2026/27	0.129

- 2025/26 has a higher fuel efficiency ratio with the introduction of the more efficient Great Plains Power Station to the SaskPower fleet
- Lower efficiency ratios in forecast years are due to enforcement of minimum operating levels at coal generating stations and the build out of new renewable projects. Both result in the potential for gas units operating at lower, less efficient output levels.

b) There can be material differences across plants based mostly on technology. Simple cycle gas turbines consume more natural gas per MWh of electrical energy produced compared to a combined cycle plant. Gas units with similar technology could see efficiency differences due to the age of the unit and the technological advances made over time.

c) The dispatch of gas units is based on the lowest variable incremental cost units being dispatched to meet SaskPower's energy and ancillary service requirements. The gas unit calculation of variable incremental costs are based on the projected natural gas commodity price, heating values of the gas supplied, heat rate of the natural gas generation, and the variable Operation and Maintenance cost of the unit or plant. The natural gas fuel efficiency results from the summation of all generation from the units dispatched to meet the demand, divided by the sum of all fuel consumed by those plants to generate the electricity.

SRRP Q35 Reference: Natural Gas

a) Please provide a schedule showing the average cost of transmission and storage per GJ for the three most recent actual years and forecasts for 2025/26 through 2026/27.

Response:

SaskPower contracts firm transportation service with TransGas for the purpose of transporting gas into and within Saskatchewan. SaskPower pays the tariff rates posted by TransGas. The table below displays the average cost of transportation (transport into Saskatchewan and within Saskatchewan).

SaskPower contracts storage capacity and withdrawal capability with TransGas. The average cost is in the table below. Both transportation and storage unit costs are relative to consumption and assume a 3% rate increase for 2026/27.

	Average Transportation Cost ($/GJ)	Average Storage Cost ($/GJ)
2022-23	$ 0.99	$ 0.13
2023-24	$ 0.82	$ 0.10
2024-25	$ 0.94	$ 0.10
2025-26	$ 1.04	$ 0.12
2026-27	$ 1.19	$ 0.13

SRRP Q36 Reference: Coal

a) Please provide the average heat values for coal generation for each of the past three actual years and forecasts for 2025-26 and 2026-27.

b) With reference to the statement on page 5 of the application that SaskPower is executing a program to life-extend its coal-fired generation facilities for 25 years, please:

i. Provide a detailed description of the Coal Fleet Repowering Initiative including current estimated timelines to refurbish each of the units and associated costs per unit.

ii. Provide copies of any and all financial and economic analyses conducted by SaskPower or the provincial government to confirm extending the life of coal facilities would be the lowest cost generation option over the long term compared to other potential generation sources.

iii. Please discuss the implications for SaskPower's existing coal supply contracts and provide a discussion of when its current contracts expire and timelines for future coal supply contract negotiations.

iv. Please discuss whether SaskPower will be able to make use of its existing carbon capture and storage facilities when the repowering initiative is complete and whether or not SaskPower has plans for additional carbon capture and storage facilities.

a) Please provide the average heat values for coal generation for each of the past three actual years and forecasts for 2025-26 and 2026-27.

Response:

Given below are the heat values for the coal supplied to both Estevan and Coronach generating units.

Coronach area

Year		2023	2024	2025	2026	2027
Heat Value	MJ/Mg	13,558	13,880	13,645	13,470	13,470

Estevan area

Year		2023	2024	2025	2026	2027
Heat Value	MJ/Mg	16,303	16,273	16,213	16,200	16,200

b) With reference to the statement on page 5 of the application that SaskPower is executing a program to life-extend its coal-fired generation facilities for 25 years, please:

 i. Provide a detailed description of the Coal Fleet Repowering Initiative including current estimated timelines to refurbish each of the units and associated costs per unit.

Response:

In response to the Government of Saskatchewan's Saskatchewan First Energy Security Strategy and Supply Plan, SaskPower launched the Coal Modernization Program. It will extend the operation of all seven of its coal-fired generating units to 2050. The generating units and associated infrastructure included in this program comprise:

- Boundary Dam Power Station (located south of the City of Estevan): Unit 3 (BD3 = 150 MW), Unit 4 (BD4 = 150 MW), Unit 5 (BD5 = 150 MW), and Unit 6 (BD6 = 300 MW)
- Shand Power Station (located east of the City of Estevan): Unit 1 (SH1 = 300MW)
- Poplar River Power Station (located east of the Town of Coronach): Units 1 and 2 (PR1 & PR2 = 300 MW each)
- The coal mines near Estevan and Coronach.
- Transmission infrastructure at all coal-fired power stations.

Listed below is the assessment schedule/status of each unit:

- BD0/6: Assessment completed, undergoing governance reviews
- PR0/2: Assessment to be completed in April 2026 (60% complete)
- PR1: Assessment to be completed in September 2026 (15% complete)
- SH0/1: Assessment to be completed in December 2026 (5% complete)
- BD3, BD4 and BD5 condition assessments to be complete in April 2027 (0% complete)

Order of magnitude estimates (+100% / - 50%) were developed in January 2025, drawing on data from the BD3 (2014) and PR1 (2008) Life Extension projects. Below are order of magnitude estimates for each unit's major life extension.

	Cost (Million $)
BD3	$ 228
CCS	254
BD4	501
BD5	189
BD6	327
BD0	56
SH1	346
PR1	356
PR2	336
PR0	38
	$ 2,629

The major life extension/unit rebuild schedule is currently as follows, and is subject to change:

- BD6 Repowering – Phase I in 2028 and Phase II in late 2029 and 2030
- PR0/PR2 Repowering in 2031
- SH0/SH1 Repowering in 2032
- PR1 Repowering in 2033
- BD3 Repowering in 2034
- BD5 Repowering - Phase I in late 2027 and early 2028, and Phase II in 2035
- BD4 Repowering in 2035
- Note: some life extension work is being advanced and/or staged outside of these dates to ensure unit reliability, optimize construction, and manage execution risks.

ii. Provide copies of any and all financial and economic analyses conducted by SaskPower or the provincial government to confirm extending the life of coal facilities would be the lowest cost generation option over the long term compared to other potential generation sources.

Response

Based on the direction to extend the life of coal rather than follow the Clean Electricity Regulations, SaskPower has reduced projected capital expenditures by more than $21 billion to 2050. This was achieved by avoiding the construction of new natural gas generation power plants equipped with Carbon Capture, and avoiding the construction of new transmission and distribution infrastructure associated with additional renewable generation. External consultants have estimated the cost of refurbishing SaskPower's 1500MW of existing coal facilities at $2.6 billion, while the cost of a new 370 MW combined cycle gas generating plant is currently $1.7 billion.

The decision to extend the life of existing coal-fired generation assets was not driven by a determination that coal life extension represents the lowest-cost generation option. Rather, the decision reflects a strategic policy choice grounded in the principles of energy security, system reliability, affordability, and the need to ensure sufficient electricity supply to support economic growth in Saskatchewan.

The provincial Energy Security Strategy sought to strengthen and expand the reliability and capacity of Saskatchewan's electricity system through a diversified, all-of-the-above approach to generation investment. This approach included weighing the value and cost of extending legacy generation assets against prevailing trends and constraints associated with new-build options. As part of this assessment, cost-benefit considerations incorporated temporal and system-specific factors, including the ability to maintain existing operating units, demand and supply-chain constraints affecting new natural gas generation, and the relative certainty associated with in situ fuel supplies available in Saskatchewan, including coal and uranium. Ultimately, the policy decision was anchored in prioritizing certainty and security of supply to ensure ongoing system reliability.

Saskatchewan's electricity system faces unique structural and transitional challenges, including limited legacy hydro resources, increasing demand associated with economic development, and the requirement to maintain reliability while transitioning to a lower-emissions grid. In this context, coal life extension provides dependable baseload capacity that supports system adequacy, operational flexibility, and diversity of supply, while reducing exposure to fuel, technology, and supply-chain risks during a period of significant change.

Coal life extension also plays a defined role as a bridge to nuclear generation, which forms the foundation of the Corporation's long-term strategy. Maintaining existing coal capacity enables the system to remain reliable and resilient while planning, licensing, and constructing nuclear generation that will support the achievement of a net-zero electricity system by 2050.

iii. Please discuss the implications for SaskPower's existing coal supply contracts and provide a discussion of when its current contracts expire and timelines for future coal supply contract negotiations.

Response

In the current contracts, supply and delivery of coal expires at the end of 2029. Negotiations have already started to amend the current contracts and to execute new contracts for the supply and delivery of coal starting in 2030. It is estimated that the new contracts and amendments to the existing contracts will be complete in 2028.

iv. Please discuss whether SaskPower will be able to make use of its existing carbon capture and storage facilities when the repowering initiative is complete and whether or not SaskPower has plans for additional carbon capture and storage facilities.

Response

In 2013-2014, Boundary Dam Unit 3 was redesigned for carbon capture integration that involved major investments in the boiler, steam turbine & generator, controls, electrical balance of plant, feedwater and steam systems. In 2034, BD3 will be repowered to life extend the operation of the power generating unit. This will involve like for like replacement of assets to extend operations to 2050. At this time, it is anticipated the carbon capture and storage facilities will continue to operate after BD3 is repowered.

Currently, SaskPower has no plans for the addition of carbon capture and storage facilities to any other power generating unit.

SRRP Q37 Reference: Hydro

a) Please provide an update on the status of potential future hydro projects, including upgrades to existing facilities and the Tazi Twé project, and discuss whether SaskPower views additional hydro capacity may be feasible in the future.

Response:

New Hydro Potential

There is some potential for new hydro development in Saskatchewan. The Tazi Twé project (51 MW) in the Far North and an additional larger project on the Saskatchewan River upstream of Nipawin (100 – 300 MW) are considered the most economic options.

Hydro cost estimates were updated in 2025. It is expected that new hydro would have a comparable cost to Small Modular Reactors (SMRs), with additional unquantified system benefits.

Tazi Twé project:

The Tazi Twé project (51 MW), which was progressed to 80% design before being put on hold in 2017 is still of potential future interest to SaskPower, especially considering the load growth in the Far North. A long lead time would be required (7-10 years) to develop the project. With the planned North-South tie line, there will be less need to match load in the Far North with local generation. However, once the transmission line is in-service, it will provide back-up for drought and the ability to send excess power south when needed. This would lower the risks associated with committing to the project, and it could be reconsidered.

Saskatchewan River project (Pehonan or alternate location):

SaskPower is not actively pursuing a project on the Saskatchewan River at this time. With the cost expected to be similar to SMRs, new hydro is an option that will be considered as we plan for net zero 2050.

Upgrades to Existing Facilities:

SaskPower continues to invest as needed to maintain the viability or our existing hydroelectric fleet. Timelines on major life extension initiatives on our larger hydro facilities are as follows:

Major Life Extension Projects

Hydroelectric Facility	Capacity (MW)	Completion (or Projected) Year
Island Falls	111	2012 (Units 4-6) 2040+ (Units 1-3, 7)

E.B. Campbell	292	2026 (Units 1-8)
Coteau Creek	186	2027 2041 (Further upgrades)
Nipawin	253	2035

Life extension work also continues to be implemented on the 3 Athabasca facilities (23 MW) as needed.

SRRP Q38 Reference: Hydro

a) Please provide a schedule showing the actual and forecasted water rental rates for the three most recent years of actuals and forecasts for 2025/26 through 2026/27.

Response:

a) The following table summarizes actual water rental rates for 2022-23 through 2024-25 and forecasted rental rates for 2025-26 and 2026-27:

Water Rental Rates

(in $/MWh)	Actual **2022-23**	Actual **2023-24**	Actual **2024-25**	Forecast **2025-26**	Forecast **2026-27**
Water Rental Rate	$ 6.10	$ 6.19	$ 6.19	$ 6.69	$ 6.84

SRRP Q39 Reference: Hydro

a) Please describe how SaskPower forecasts hydro generation availability including any historical data inputs.

b) Please provide any updates on the expected flow conditions for 2026-27 based on recent snowfall or other conditions since the business plan supporting the rate application was prepared.

c) Please discuss whether SaskPower has prepared an analysis of the potential effects of climate change on future hydro generation and if so, provide a summary of the analysis.

Response:

a) As part of standard industry practice, SaskPower utilizes the historical hydro generation data over the most recent last 30-year time-period to derive the estimated percentiles. These percentiles are subsequently evaluated and calibrated based on the current hydrological condition and the current water management operations to develop the most accurate and representative hydro generation projection.

b) There are hydrological factors which could provide either above or below median flow on the Saskatchewan and Churchill River systems this year. There is a greater chance of below median flows, however it is too early to assign a firm degree of confidence to this. Two key factors are mountain snowpack conditions and spring precipitation in the headwaters. Although current mountain snowpack conditions generally range from above-normal to well above-normal, the bulk of the meaningful snowpack season is still to come. Median flow conditions are still projected as the expected flow conditions for business planning purposes.

c) SaskPower continually reviews various climate change projections, incorporating immediately identifiable impacts into short-term operating plans. Although ad-hoc analysis is conducted, official analysis of climate change impacts on hydro generation has not been performed in depth at this time.

SRRP Q40 Reference: Wind

a) Please provide a schedule showing actual and forecasted monthly wind generation in GWh and wind capacity factors for wind facilities for the last three actual years and forecasts for 2025-26 and 2026-27.

Response:

The following table summarizes wind generation actuals in GWhs for the 2022-23 through 2024-25 fiscal years as well as forecasted amounts for the 2025-26 and 2026-27 fiscal years.

Wind Energy by Month

(GWh)	Actual 2022-23	Actual 2023-24	Actual 2024-25	Forecast 2025-26	Forecast 2026-27
April	231	189	214	224	209
May	190	127	171	262	226
June	172	110	178	210	182
July	120	150	94	144	204
August	130	136	137	169	237
September	186	138	204	196	200
October	178	197	230	332	334
November	236	210	218	311	311
December	175	243	280	250	250
January	186	155	334	355	357
February	222	171	277	191	191
March	153	156	194	211	212
Total	2,177	1,981	2,531	2,855	2,913

The below table outlines wind capacity in MWhs for the 2022-23 through 2024-25 fiscal years as well as forecasted amounts for 2025-26 through 2026-27 fiscal years.

Wind Energy Capacity

(net MWh)	Actual 2022-23	Actual 2023-24	Actual 2024-25	Forecast 2025-26	Forecast 2026-27
Annual capacity	617	617	818	818	818

SRRP Q41 Reference: Purchase Power Agreements

a) Have SaskPower's requirements for IPPs related to decommissioning, site remediation and site restoration changed since the response to first round SRRP-Q44 from the previous GRA? If so, please provide an update to that response.

b) With reference to the solar RFP being undertaken by the First Nations Power Authority described on page 31 of the application, please describe SaskPower's arrangements with the First Nations Power Authority for the supply of power and provide any updates on timing for results of the proposal process.

Response:

a) SaskPower's requirements for IPPs related to decommissioning, site remediation and site restoration have not changed since our last response.

b) SaskPower engaged the First Nations Power Authority (FNPA) to lead a competitive solicitation to secure 100 MW of solar generated power. The competition closed on March 31, 2025. FNPA notified SaskPower on May 30, 2025 that Neoen Lajord Solar Ltd. had been selected as the top proponent in the competition. The name of the project was later changed to Mino Giizis. In December 2025, SaskPower executed a PPA with Mino Giizis Solar Ltd, which is a partnership between Neoen Holding Canada Inc. (50%) and Anishinabek Power Alliance Ltd. (50%). Anishinabek Power Alliance was created through a partnership of four First Nations (Kinistin Saulteaux Nation, Zagime Anishinabek, Cote First Nation 366, and The Key First Nation), all of which are new to power generation. The facility will be located about 25 km southeast of Regina, in the RM of Lajord and is expected to be operational by Q4 2028.

SRRP Q42 Reference: Imports

a) Please provide a schedule showing actual and forecasted import volumes and average prices separately for firm import contracts and spot market or short-term contracts for each of the last four actual years and forecasts for 2025-26 and 2026-27.

b) Please discuss any current plans SaskPower has to increase import capabilities from other jurisdictions.

Response:

This response contains confidential information and cannot be released publicly. However, a full response has been provided to the Saskatchewan Rate Review Panel for their review.

SRRP Q43 Reference: Solar and Other

a) Please provide an explanation for the forecast increase in other fuel and purchased power expense and volumes for 2025-26 and 2026-27.

b) With reference to the discussion on page 8 of SaskPower's 2024-25 annual report, please discuss the benefits and costs of the utility scale 20 MW battery project. Does SaskPower anticipate deploying more utility scale batteries?

Response:

a) Other fuel and purchased power includes additional generation sources such as solar (both utility-scale solar and through our Power Generation Partners Program), waste heat, biomass, landfill gas, flare gas, customer-generated wind through our Power Generation Partners Program and liquefied natural gas (LNG).

At the time of the Rate Application, SaskPower was forecasting the 100-MW Turning Sun Solar Energy Project near Estevan would come online in 2026-27. Increased generation from our waste heat facilities and Power Generation Partners Program also contributed to the increase in fuel expenses and volumes.

b) The 20-MW utility-scale battery energy storage system supports intermittent power sources such as wind and solar and will help SaskPower respond to short-term spikes in demand. The capital costs of this project were $34 million, with $13 million in federal funding received under the Investing in Canada Infrastructure – Green Stream grant, for a net cost of $21 million.

There are currently no plans to deploy additional utility-scale batteries.

SRRP Q44 Reference: Operating, Maintenance and Administration (OM&A)

a) Please provide a schedule that breaks out actual and forecast total OM&A costs for the three most recent actual fiscal years and forecasts for the test years in a format similar to the response to SRRP Pre-Ask 7 from the 2022 and 2023 Rate Application.

b) Please provide a comparison of the 2021/22, 2022/23, and 2023/24 forecasts from the last Rate Application and actual OM&A spending for 2021/22, 2022/23, and 2023/24 and current forecasts for 2025/26 and 2026/27. Please discuss the reasons for any material variances.

c) Please provide an explanation for year over year changes in actual and forecast salaries and wage expenses noting changes driven by:

   i. staff or employee complement
   ii. average salary costs per position
   iii. overtime costs
   iv. vacancy rates
   v. corporate credits
   vi. labour credits

d) Please discuss any efficiency initiatives undertaken since the previous rate application or forecast for the test years to reduce OM&A and demonstrate how they are quantified and reflected in the current rate application.

Response:

Please refer to the tables on the following pages.

a)

Operating, Maintenance and Administration Expense

(in millions)	Actual **2022-23**	Budget **2022-23**	$ **Variance**	% **Variance**
Salaries and wages	$ 353	$ 354	$ (1)	(0.3%)
Benefits	76	75	1	1.3%
Salaries and benefits	429	429	-	0.0%
Premium pay	42	34	8	23.5%
Subtotal wages & salaries	471	463	8	1.7%
Materials and supplies	57	49	8	16.3%
Contract services	248	232	16	6.9%
Consulting services	16	13	3	23.1%
Advertising expenses	2	2	-	0.0%
External services	266	247	19	7.7%
Training expenses	3	3	-	0.0%
Travel expenses	12	10	2	20.0%
Administrative expenses	19	18	1	5.6%
Insurance expenses	15	15	-	0.0%
Bad debt expense	5	5	-	0.0%
Tools and Equipment Rental Expenses	4	3	1	33.3%
Vehicle expenses	26	21	5	23.8%
Property expenses	7	7	-	0.0%
Other	91	82	9	11.0%
Corporate credits	(93)	(101)	8	(7.9%)
Grants	-	-	-	0.0%
Total OM&A	$ 792	$ 740	$ 52	7.0%

Operating, Maintenance and Administration Expense

(in millions)	Actual **2023-24**	Budget **2023-24**	$ **Variance**	% **Variance**
Salaries and wages	$ 379	$ 381	$ (2)	(0.5%)
Benefits	84	81	3	3.7%
Salaries and benefits	463	462	1	0.2%
Premium pay	43	38	5	13.2%
Subtotal wages & salaries	506	500	6	1.2%
Materials and supplies	58	58	-	0.0%
Contract services	247	252 -	5	(2.0%)
Consulting services	24	25 -	1	(4.0%)
Advertising expenses	2	3 -	1	(33.3%)
External services	273	280 -	7	(2.5%)
Training expenses	3	3	-	0.0%
Travel expenses	14	11	3	27.3%
Administrative expenses	20	18	2	11.1%
Insurance expenses	18	18	-	0.0%
Bad debt expense	8	5	3	60.0%
Tools and Equipment Rental Expenses	4	3	1	33.3%
Vehicle expenses	27	23	4	17.4%
Property expenses	6	5	1	20.0%
Other	100	86	14	16.3%
Corporate credits	(104)	(103)	(1)	1.0%
Grants	(22)	(24)	2	(8.3%)
Total OM&A	$ 811	$ 797	$ 14	1.8%

Operating, Maintenance and Administration Expense

(in millions)	Actual **2024-25**	Budget **2024-25**	$ **Variance**	% **Variance**
Salaries and wages	$ 415	$ 409	$ 6	1.5%
Benefits	93	87	6	6.9%
Salaries and benefits	508	496	12	2.4%
Premium pay	46	39	7	17.9%
Subtotal wages & salaries	554	535	19	3.6%
Materials and supplies	68	65	3	4.6%
Contract services	278	290	(12)	(4.1%)
Consulting services	17	11	6	54.5%
Advertising expenses	2	4	(2)	(50.0%)
External services	297	305	(8)	(2.6%)
Training expenses	3	4	(1)	(25.0%)
Travel expenses	15	13	2	15.4%
Administrative expenses	22	20	2	10.0%
Insurance expenses	18	20	(2)	(10.0%)
Bad debt expense	4	5	(1)	(20.0%)
Tools and Equipment Rental Expenses	4	3	1	33.3%
Vehicle expenses	26	26	-	0.0%
Property expenses	5	5	-	0.0%
Other	97	96	1	1.0%
Corporate credits	(115)	(115)	-	0.0%
Grants	(36)	(39)	3	(7.7%)
Total OM&A	$ 865	$ 847	$ 18	2.1%

Operating, Maintenance and Administration Expense

(in millions)	Forecast **2025-26**	Forecast **2026-27**
Salaries and wages	$ 434	$ 467
Benefits	95	102
Salaries and benefits	529	569
Premium pay	49	44
Subtotal wages & salaries	578	613
Materials and supplies	78	76
Contract services	324	341
Consulting services	16	15
Advertising expenses	3	3
External services	343	359
Training expenses	3	4
Travel expenses	15	15
Administrative expenses	26	26
Insurance expenses	19	20
Bad debt expense	4	5
Tools and Equipment Rental Expenses	4	4
Vehicle expenses	26	26
Property expenses	5	5
Other	102	105
Corporate credits	(125)	(126)
Grants	(43)	(40)
Total OM&A	$ 933	$ 987

Note: Operating, maintenance and administration cost category allocation in 2026-27 has not yet been finalized and is subject to change.

b)

Operating, Maintenance and Administration Expense							
			2022-23 rate				
		Actual	application		$	%	
(in millions)		**2021-22**		**2021-22**		**Variance**	**Variance**
Total OM&A	$	711	$	710	$	1	0.1%

Operating, Maintenance and Administration Expense							
			2022-23 rate				
		Actual	application		$	%	
(in millions)		**2022-23**		**2022-23**		**Variance**	**Variance**
Total OM&A	$	792	$	740	$	52	7.0%

Operating, Maintenance and Administration Expense							
			2022-23 rate				
		Actual	application		$	%	
(in millions)		**2023-24**		**2023-24**		**Variance**	**Variance**
Total OM&A	$	811	$	765	$	46	6.0%

Operating, Maintenance and Administration Expense							
		Forecast		Forecast		$	%
(in millions)		**2026-27**		**2025-26**		**Variance**	**Variance**
Total OM&A	$	987	$	933	$	54	5.8%

2021-22: No material variances.

2022-23: There was an unfavourable variance of $52 million driven by greater emergency maintenance required to repair distribution infrastructure damaged by severe weather; additional overhauls on our generating facilities; and higher feasibility study costs on Small Modular Reactors.

2023-24: There was an unfavourable variance of $46 million driven by emergency maintenance in response to flooding at the Poplar River Power Station, increased transmission and distribution maintenance activities, and an increase in full-time equivalents to support our distribution transformation initiatives.

2026-27: A year-over-year variance of $54 million is expected in 2026-27, with the main drivers including costs related to Coal Revitalization and Aspen resourcing, higher nuclear development costs, and inflationary increases to all business units.

c)

i) Staff or employee complement

	Actual 2022-23	Actual 2023-24	Actual 2024-25	Forecast 2025-26	Forecast 2026-27
Total FTEs	3,416	3,544	3,643	3,679	3,767

ii) Average salary cost per position

	Actual 2022-23	Actual 2023-24	Actual 2024-25	Forecast 2025-26	Forecast 2026-27
Salaries and benefits (in millions)	$ 428,614	$ 463,249	$ 507,836	$ 528,984	$ 569,066
Total FTEs	3,416	3,544	3,643	3,679	3,767
Average salaries and benefits per FTE (in dollars)	$ 125,472	$ 130,714	$ 139,400	$ 143,785	$ 151,066
Year over year change	-	4.2%	6.6%	3.1%	5.1%

iii) Overtime Costs

(in millions)	Actual 2022-23	Actual 2023-24	Actual 2024-25	Forecast 2025-26	Forecast 2026-27
Overtime costs	$ 42	$ 43	$ 46	$ 49	$ 44

Note: Operating, maintenance and administration cost category allocation in 2026-27 has not yet been finalized and is subject to change.

iv) Vacancy rates

SaskPower's vacancy rates vary. SaskPower budgets 3% vacancy rates for workforce planning purposes.

v) Corporate credits & vi) Labour Credits

(in millions)	Actual 2022-23	Actual 2023-24	Actual 2024-25	Forecast 2025-26	Forecast 2026-27
Labour credits	$ 52	$ 57	$ 62	$ 67	$ 68
Vehicle credits	10	12	11	12	12
Overhead	23	27	27	29	29
Material returns	8	8	15	17	17
	$ 93	$ 104	$ 115	$ 125	$ 126

Note: Operating, maintenance and administration cost category allocation in 2026-27 has not yet been finalized and is subject to change.

d) The Annual Business Plan for 2024-25, and 2025-26 included a 1% efficiency target allocated to all areas. These efficiencies were left to the discretion of the VP and Director teams, and consisted of vacancy management, reductions in contract and external services, as well as reducing discretionary spending. These reductions were considered permanent in nature and have been incorporated into the 2026-27 OM&A budgets.

SRRP Q45 Reference: Operating, Maintenance and Administration (OM&A)

a) Please provide the actual vacancy rates for the three most recent years and forecasts for 2025/26 through 2026/27.

b) Please discuss how SaskPower forecasts vacancy rates for business planning purposes.

Response:

a) Vacancy rates

Operating, maintenance and administration FTEs	Actual 2022-23	Actual 2023-24	Actual 2024-25	Forecast 2025-26	Forecast 2026-27
Vacancy Rates (%)	5.1%	5.0%	4.9%	5.1%	3.0%

b) Business planning

For business planning purposes, SaskPower forecasts vacancy rates using a combination of industry benchmarks and historical organizational trends. At the corporate level, we apply a vacancy rate of approximately 3%, which reflects the typical level of turnover expected at any point in time across a large utility workforce.

In addition to this baseline, we incorporate area specific historical performance. Certain operational groups have consistently experienced higher vacancy levels—often closer to 5%—due to factors such as competitive labour markets, specialized skill requirements, or regional workforce challenges. These higher historical vacancy rates are factored directly into our planning assumptions to ensure resource forecasts remain realistic and aligned with operational needs.

This blended approach allows SaskPower to create a more accurate and reliable workforce plan by accounting for both organization wide expectations and localized staffing patterns.

SRRP Q46 Reference: Operating, Maintenance and Administration (OM&A)

a. Please provide an update to the response to Round 1 SRRP Q47 from the 2022 and 2023 rate application adding any actual year results available since 2020/21.

b. Please provide an explanation for any material variances between forecasts and actuals in the information provided in the response to part (a).

Response:

a) The following table shows both the actual and forecasted OM&A spend, customer accounts, and the average OM&A per customer account for 2021-22 through 2024-25.

OM&A per customer account

	Actual **2021-22**	Actual **2022-23**	Actual **2023-24**	Actual **2024-25**
OM&A (millions)	$ 711	$ 792	$ 811	$ 865
Total of customer accounts	549,940	553,849	557,443	562,232
OM&A per customer account	$ 1,293	$ 1,430	$ 1,455	$ 1,539

	Forecast **2021-22**	Forecast **2022-23**	Forecast **2023-24**	Forecast **2024-25**
OM&A (millions)	$ 705	$ 740	$ 797	$ 847
Total of customer accounts	551,240	561,685	558,716	565,076
OM&A per customer account	$ 1,279	$ 1,317	$ 1,426	$ 1,499

2021-22: There was an unfavourable variance of $6 million due to greater emergency maintenance required to repair distribution infrastructure and higher overhaul costs at our generating facilities.

2022-23: There was an unfavourable variance of $52 million driven by greater emergency maintenance required to repair distribution infrastructure damaged by severe weather; additional overhauls on our generating facilities; and higher feasibility study costs on Small Modular Reactors.

2023-24: There was an unfavourable variance of $14 million driven by emergency maintenance in response to flooding at the Poplar River Power Station, and increased transmission and distribution maintenance activities.

2024-25: There was an unfavourable variance of $18 million driven by higher overhaul costs at our generation facilities and increased transmission maintenance activities.

SRRP Q47 Reference: Operating, Maintenance and Administration (OM&A)

a) Please provide a breakout of SaskPower's OM&A spending by business unit for each of the five most recent years of actuals and forecasts for 2025/26 through 2026/27.

Response:

The following table provides OM&A actuals by business unit for the 2020-21 through 2024-25 years and forecasts for 2025-26 and 2026-27 based on the current structure:

Operating, Maintenance & Administration - by Business Unit							
	Actual	Actual	Actual	Actual	Actual	Forecast	Forecast
(in millions)	**2020-21**	**2021-22**	**2022-23**	**2023-24**	**2024-25**	**2025-26**	**2026-27**
President /Board	$ 3	$ 2	$ 2	$ 2	$ 2	$ 3	$ 3
Operations							
Operations Other	6	7	8	8	9	8	9
System Operations	15	16	18	20	24	26	28
Generation	226	230	243	248	275	303	307
Transmission & Distribution	166	179	196	198	209	214	219
Engineering & Construction	57	62	65	72	77	86	91
Total Operations	470	494	530	546	594	637	654
Strategy, Technology & Finance							
Nuclear Development	1	4	11	17	28	37	50
Asset Strategy & Planning	49	54	57	62	62	75	79
Technology	91	95	103	106	109	118	123
Finance & Strategy	15	14	15	17	17	18	20
Total Strategy, Technology & Finance	156	167	186	202	216	248	272
People, Safety & Corporate Relations	32	33	34	39	42	44	46
Customer Experience & Procurement	32	33	36	44	50	53	57
Legal & Corporate Services	72	62	63	63	69	71	74
Total core costs	**765**	**791**	**851**	**896**	**973**	**1,056**	**1,106**
Insurance expense	9	12	15	18	17	18	19
Bad debt expense	7	1	6	8	4	4	5
Other expense	-	1	2	2	9	4	5
PPA - OMA	11	11	11	13	13	19	19
Total other costs	**27**	**25**	**34**	**41**	**43**	**45**	**48**
OM&A before corporate credits	792	816	885	937	1,016	1,101	1,154
Corporate credits	(92)	(95)	(93)	(104)	(115)	(125)	(127)
Grants	-	(10)	-	(22)	(36)	(43)	(40)
TOTAL OM&A	$ 700	$ 711	$ 792	$ 811	$ 865	$ 933	$ 987

SRRP Q48 Reference: Operating, Maintenance and Administration (OM&A)

a) Please provide the actual overhaul spending for the three most recent years and forecasts for 2025-26 through 2026-27.

Response:

Operating, maintenance and administration
Overhaul Spending

(in millions)	Actual 2022-23	Actual 2023-24	Actual 2024-25	Forecast 2025-26	Forecast 2026-27
TOTAL OM&A	**$56**	**$37**	**$63**	**$83**	**$82**

SRRP Q49 Reference: Operating, Maintenance and Administration (OM&A)

a) Please indicate when the current collective agreements are set to expire and provide an update on the status of any negotiations for future collective agreements.

b) With reference to the response to SRRP Q51 (b) from the 2022 and 2023 rate application please provide an updated breakdown of FTEs between employees covered by collective agreements and those excluded from collective agreements for all actual years available.

Response:

a) SaskPower has two collective bargaining agreements (IBEW Local 2067 and UNIFOR Local 649), both of which expired on December 31, 2025. Negotiations to renew the IBEW agreement began in October 2025 and are ongoing. Negotiations with UNIFOR, originally scheduled for January 2026, have been delayed at UNIFOR's request.

b) FTE breakdown:

Operating, maintenance and administration
FTE Complement

	Actual 2022-23	Actual 2023-24	Actual 2024-25	Forecast 2025-26	Forecast 2026-27
Employees not covered by collective agreements	1,270	1,389	1,399	1,488	1,570
Employees covered by collective agreements	2,146	2,156	2,244	2,191	2,197
TOTAL FTEs	**3,416**	**3,544**	**3,643**	**3,679**	**3,767**

SRRP Q50 Reference: Operating, Maintenance and Administration (OM&A)

a) Please provide a schedule that breaks out spending on advertising, communications, marketing, donations and sponsorships for the three most recent actual years and forecasts for the test years.

b) Please provide the dollar values and recipients of SaskPower's five largest donations or sponsorships for each of the three most recent actual years.

c) Please discuss how SaskPower selects the recipients of its donations and sponsorships.

d) Please confirm donations and sponsorships are included in the total OM&A figures in the table on page 26 of the application.

Response:

a) Adverting/Marketing

SaskPower advertising is largely aimed at creating awareness of SaskPower programs and services, including low-income programming, informing the public of construction work happening in their area, supporting public engagement related to SaskPower projects, and promoting safety around power lines. The following is a breakdown of advertising spending over the last three years.

Actual 2022-23	Actual 2023-24	Actual 2024-25	YTD 2025-26 (As of Feb. 23, 2026)
$682,368	$736,814	$748,231	$804,531

Given the volume of infrastructure work happening across the province in the coming years, we would forecast advertising expenses in 2026-2027 to be in line with the total for 2025-26.

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2026 AND 2027 RATE APPLICATION
SRRP INTERROGATORIES

Community Investment

	Actual 2022-2023	Actual 2023-2024	Actual 2024-2025	Forecast 2025-2026	Forecast 2026-2027
Community Partnerships & Investment	$2,040,658	$1,855,309	$2,399,833	$2,400,500	$2,500,500
Environmental regulatory requirements and strategic investment	$410,000	$612,000	$491,500	$532,500	$532,000
Post-Secondary Education Funding	0	$168,509	0	$50,000	$50,000
Indigenous Partnerships & Strategic Investment	$548,250	$567,731	$453,697	$424,000	$436,000
Total Investment	$2,998,908	$3,023,549	$3,345,530	$3,407,000	$3,518,500

b) Largest Donations

Top 5 Donations – FY2023

STARS - $400,000
Saskatchewan Science Centre - $343,963
Town of Coronach - $240,000
Saskatchewan Indian Institute of Technologies - $146,000
University of Saskatchewan - $87,000

Top 5 Donations – FY2024

STARS - $400,000
Saskatchewan Science Centre - $351,850
Saskatchewan Indian Institute of Technologies - $149,000
Hector Thiboutot Community School - $131,000
Saskatchewan Roughrider Football Club - $113,000

Top 5 Donations – FY2025

Saskatchewan Indian Institute of Technologies - $496,000
STARS - $400,000
Saskatchewan Science Centre - $358,000
RM of Estevan - $300,000
Town of Coronach - $150,000

c) Adjudication Process

Please see attached Community Partnerships & Investment Policy

d) Donations and sponsorships included in the total OM&A figures

Confirmed.

COMMUNITY PARTNERSHIPS & INVESTMENT POLICY

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Division	Corporate & Regulatory Affairs
Policy Title	Community Partnerships & Investment Policy
Issue Date	3/11/2021
Revision Frequency	5 years

POLICY STATEMENT

Purpose:

SaskPower's strategic plan requires us to gain social licence and public trust as we rebuild lines, add new generation and support provincial growth. This policy outlines SaskPower's commitment to align our Community Partnerships & Investment program to the company's strategic direction while also making a real difference with our community partners.

Our Community Partnerships & Investment program encompasses community investment, employee volunteering, sponsorship, community relations, stakeholder relations, CIC provincial projects and executive support. Of these categories, community investment is the primary focus of this policy.

APPLICABILITY

Applies to:	This policy applies to all SaskPower officers and employees partnering with or sponsoring non-profit or charitable organizations on behalf of SaskPower.

REQUIREMENTS

Responsibilities:

SaskPower seeks to ensure in all community investment:

- All Community Investment opportunities are of mutual benefit to SaskPower and Saskatchewan communities

- Our audiences easily make the connection from our community activities to SaskPower's business and message
- Our audiences associate SaskPower with specific sponsorships and community initiatives, unprompted
- Our program is considered industry best practice and benchmarked by other professional organizations

ELIGIBILITY for community investment:

SaskPower's Community Investment program is focused on education programming. By educating our audiences about behaviour change, we align to SaskPower's business priorities and leave a lasting mark in our communities:

- Workforce excellence — building our next generation of employees
- Safety — keeping our customers safe around electricity
- Conservation and efficiency — creating a community of customers who find ways to save power and protect our environment

Targeted demographics align to business needs:

- Indigenous
- Gender and diversity
- Youth
- Broad provincial representation

Through the broad Community Partnerships & Investment program funds are also set aside for planned activities in the following categories:

- Executive support. Visibility of SaskPower's executive team is important to SaskPower's reputation. A portion of our annual sponsorship budget will be reserved for these activities, at the discretion of the President.
- Crown alignment. Through CIC, each Crown contributes to major initiatives deemed worthy of a united Crown presence.
- Stakeholders. The purpose of our stakeholder initiatives is to build business relationships in communities across the province. We find speaking and engagement opportunities with relevant organizations aligned to our messages and designed to enhance our relationships with community leaders.
- Promotional items. In order to be present at smaller community events, we distribute promotional items at a grassroots fundraising level. Any Saskatchewan organization raising money for a Saskatchewan non-profit or charity project or event will be eligible for a promotional item to assist in their efforts once per fiscal year.

Conditions:

The following are ineligible for funding under this policy (unless approved by the President & CEO):

- Out-of-province organizations
- Individuals
- Political organizations and political parties
- Advocacy groups
- Organizations that discriminate on the basis of ethnic origin, gender, sexuality, colour, language, national or social origin, economic status, religion, political or other contentiously held beliefs
- Religious organizations and churches (unless providing community services and activities without promoting religious or other contentiously held beliefs)
- Travel, accommodation, meal expenses, field trips or tours
- Organizations that rely upon SaskPower as the sole funder for their operations
- Organizations seeking investment for capital projects
- Organizations without a tax-registered number or non-profit society number
- For-profit community endeavors
- Donation of electricity or electrical services

Groups that meet eligibility requirements may be denied funding due to budget constraints.

Governance:

- All sponsorships are reviewed annually to ensure objectives of both parties are met.
- All applications must be completed online.
- All SaskPower donations are managed out of the corporation's Community Partnerships & Investment group within Corporate Relations & Communications.
- Sponsorship opportunities are reviewed, and decisions made in consultation with business units to ensure strategic corporate needs are met.
- Employees involved in decisions affecting sponsorship must declare if they volunteer with an organization to whom sponsorship dollars are to be allocated.

RESOURCES

Related Policies:

Code of Conduct Policy

Indigenous Relations Policy

Appendix

n/a

Ownership & Inquiries

Position Owner	Consultant
Business Department	Corporate Relations & Communications
Contact Person	Verna Williamson
Approved by	Board of Directors
Date	3/11/2021
Contact Information	306.566.3575

Document History

Revised by	**Revision Purpose**	**Date**
Board of Directors	Overhauled three existing policies into one CP&I policy reflecting corporate strategic direction	12/13/2013
Board of Directors	Changed title of policy and clarified language regarding restrictions	12/15/2015
Board of Directors	Added Code of Conduct language to governance section	3/11/2021

SRRP Q51 Reference: Operating, Maintenance and Administration (OM&A)

a) Please summarize SaskPower's overtime policies and describe how SaskPower forecasts overtime.

b) Please summarize SaskPower's standby pay policies and describe how SaskPower forecasts standby pay requirements for the test years.

Response:

A) SaskPower's overtime provisions differ for management employees and employees represented by collective bargaining agreements, reflecting the operational and contractual framework applicable to each group.

For management employees, overtime is governed by a corporate policy and is intended to be kept to a minimum. Overtime must generally be authorized in advance and is compensated at 1.5 times their regular rates of pay or through time off in lieu when directed and approved. Due to the nature of management roles, occasional additional hours worked beyond the normal workday may not be eligible for overtime compensation. In addition, certain management and professional positions are exempt from overtime provisions in accordance with the Saskatchewan Employment Act and are not eligible for overtime compensation.

For employees represented by the IBEW Local 2067, overtime eligibility, compensation, and administration are governed by the collective bargaining agreement. Overtime is paid at premium rates, double their regular rate of pay, and includes additional provision such as minimum call-out provisions, rest period protections, and the ability to bank overtime for future use or payout, subject to defined limits and approval requirements.

For employees represented by UNIFOR Local 649, overtime is also governed by collective bargaining agreement provision. Overtime is paid at double the regular rate of pay for hours worked beyond the standard work scheduled. Employees are eligible for minimum call-out payments and rest period protections and may bank overtime at a rate of two regular hours for each overtime hour worked, subject to limits on accumulated balances and scheduling based on operational requirements and management approval.

In summary, management overtime is governed by internal policy and applied on a discretionary basis, while overtime for IBEW and UNIFOR employees is governed by collective agreements that establish defined eligibility, compensation rates, minimum guarantees, and banking provisions.

Overtime forecasts are based on prior year trends, as well as what maintenance plans are currently underway.

B) Stand-by coverage at SaskPower ensures employees are available to respond to operational and customer service requirements outside of regular working hours. Stand-by provisions differ by employee group and are governed by the applicable collective bargaining agreements or corporate practice.

For employees represented by IBEW Local 2067, stand-by pay is provided in accordance with the collective bargaining agreement and applicable only for days of rest (weekends) and statutory holidays. Employees scheduled for standby received premium pay at the rate of 4 hours of straight time pay per day, plus an eight per cent premium for such availability. Employees called out while on standby are compensated in accordance with the overtime provisions in the agreement.

For employee represented by UNIFOR LOCAL 649, stand-by pay is provided in accordance with the collective bargaining agreement and Letters of Understanding. Employees assigned to standby are scheduled on a rotational basis and receive a premium equal to 12.5% of their regular hourly rate for each hour on stand-by. Employees called while on stand-by are compensation in accordance with the overtime provisions of the agreement. Standby coverage for UNIFOR-represented employees is limited and mainly applies to SaskPower's outage center.

For management employees, standby or on-call responsibilities may be assigned based on the operational requirements and nature of the position. Management employee may be compensated through time in lieu or overtime, where applicable. Certain management and professional positions are exempt from overtime provisions in accordance with the Saskatchewan Employment Act.

Stand-by coverage forecasts are based on prior year trends and dependent on upcoming maintenance plans.

2026 AND 2027 RATE APPLICATION
SRRP INTERROGATORIES

SRRP Q52 Reference: Operating, Maintenance and Administration (OM&A)

a) Does SaskPower have bonus or at-risk pay incentive structures for any employees? If so, please provide a summary of any such programs.

Response:

SaskPower management (out-of-scope) employees are eligible for a Salary Holdback Program, which is a pay at risk contingent on a combination of Individual and Corporate performance thresholds being met. Salary holdback does not form part of base pay, and is pensionable.

The payment is calculated as an annual lump sum payout that is a percentage of base pay; additional components are as follows:

- Eligible employees must obtain a performance rating of fully achieves or higher
- The corporate component is evaluated by the SaskPower Board of Directors to determine the corporate performance rating
- Different levels of the organization have varied holdback percentages and weightings of corporate/individual performance
- The Salary Holdback Policy is governed by Crown Investment Corporation policy.

Compensation Level	Holdback Percentage	Corporate Performance Weighting	Individual Performance Weighting
Exec - President & CEO	8.33%	80%	20%
Exec - VP 2	5.83%	70%	30%
Exec - VP 1	5%	70%	30%
Band 7, Band 6, Band 5 L 2, Band 5 L 3	8%	60%	40%
Band 5 L 1, Band 4	5%	40%	60%
Band 3, Band 2, Band 1	3%	20%	80%

SRRP Q53 Reference: Operating, Maintenance and Administration (OM&A)

a) Please provide SaskPower's calculations and underlying data for its OM&A per customer account and OM&A per residential account for all years presented in the 2026–27 GRA. This request includes the data used to produce the "OM&A per residential account" figure shown on page 26 of the 2026–27 GRA.

b) Please explain any differences between these metrics and the "OM&A per customer account" values reported in the 2024–25 Annual Report.

Response:

a)

	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27
OM&A ($M)	675	680	708	705	700	711	792	811	869	947	987
Residential customer accounts	388,006	392,314	396,536	399,394	403,782	407,995	411,629	415,037	419,908	422,075	426,255
OM&A per residential account	1,739.66	1,733.31	1,785.46	1,765.17	1,733.61	1,742.67	1,924.06	1,954.04	2,069.50	2,243.68	2,315.52
OM&A per residential account growth		-0.4%	3.0%	-1.1%	-1.8%	0.5%	10.4%	1.6%	5.9%	8.4%	3.2%
Average growth		2.90%	2.90%	2.90%	2.90%	2.90%	2.90%	2.90%	2.90%	2.90%	2.90%
CPI											
Annual Saskatchewan CPI	1.1%	1.7%	2.3%	1.7%	6.0%	3.0%	4.0%	4.0%	1.4%	2.0%	2.0%
Average Saskatchewan CPI		2.80%	2.80%	2.80%	2.80%	2.80%	2.80%	2.80%	2.80%	2.80%	2.80%

An Excel file has also been provided.

b)

The information presented in the rate application document measures OM&A per residential customer account annually and over a 10-year period including the test years.

SaskPower's annual OM&A per Customer Account metric reported in the annual report is part of SaskPower's Corporate Balanced Scorecard and measures the five-year average growth of OM&A expenses on an overall per customer basis against the five-year average growth of Saskatchewan CPI.

2026 AND 2027 RATE APPLICATION
SRRP INTERROGATORIES

SRRP Q54 Reference: Nuclear

a) With reference to the statement on page 5 of the application that "SaskPower is undertaking planning and project development work required to deploy nuclear power starting in the mid to late 2030s." Please provide a schedule showing all costs related to nuclear planning and development work included in the last 3 actual years and forecast for the test years.

b) Please clarify confirm if the mid to late 2030s timeline is the anticipated timeline for nuclear power to begin to be delivered to SaskPower's grid. If not, please explain. If yes, please indicate when SaskPower anticipates it would begin the regulatory approvals process.

c) Please provide copies of any publicly available collaboration agreements or funding agreements related to the nuclear planning and project development work.

Response:

a)

Nuclear development

(in millions)	Actual 2022-23	Actual 2023-24	Actual 2024-25	Forecast 2025-26	Forecast 2026-27
OM&A	$ 11.0	$ 16.5	$ 27.9	$ 37.4	$ 50.0
Less external funding					
NRCan - EPP	$ -	$ (14.9)	$ (26.1)	$ (8.2)	$ -
ECCC - FEF (return on Federal Carbon Tax)	$ -	$ (1.5)	$ -	$ (11.8)	$ (25.0)
Government of Saskatchewan - CETG	$ -	$ -	$ -	$ (9.9)	$ -
Total external funding for nuclear development	$ -	$ (16.4)	$ (26.1)	$ (29.9)	$ (25.0)
Net cost - nuclear development	**$ 11.0**	**$ 0.1**	**$ 1.8**	**$ 7.5**	**$ 25.0**

b) Yes, SaskPower is advancing project planning and regulatory work on a schedule to achieve a Commercial Operating Date for the first SMR in the mid to late 2030s.

c) SaskPower is a party to the following collaboration and funding agreements related to nuclear planning and project development work:

1) SaskPower – Westinghouse-Cameco Memorandum of Understanding (MOU);

2) SaskPower – New Brunswick Power Collaboration Agreement;

3) SaskPower - Electricity Pre-development Program Contribution Agreement; and

4) Crown Investments Corporation - Future Electricity Fund Agreement.

These agreements are confidential and cannot be released publicly but a copy has been provided to the Saskatchewan Rate Review Panel for their review.

SRRP Q55 Reference: OM&A – Distribution system reliability

a) With reference to page 26 of the application, please provide a schedule showing the number of positions and costs related to additional resources to modernize and maintain SaskPower's distribution grid for each of the last three actual years and forecasts for 2025/26 through 2026/27.

Response:

Operating, maintenance and administration
Distribution System Reliability

(in millions)	Actual 2022-23	Actual 2023-24	Actual 2024-25	Forecast 2025-26	Forecast 2026-27
TOTAL OM&A	**$12**	**$14**	**$19**	**$22**	**$22**
FTEs/Positions	**61**	**82**	**93**	**101**	**108**

The information above includes employees & related costs in the areas of AMI Deployment & Operations, the Distribution Control Office as well as the Distribution Asset Management Grid Modernization project/planning team.

SRRP Q56 Reference: OM&A – Vegetation management

a) Please provide a schedule showing the costs related to vegetation management included in total OM&A for each of the last three actual years and forecasts for 2025/26 through 2026/27.

b) Please describe SaskPower's vegetation management processes e.g. mechanical clearing, chemical/herbicide, other methods and explain why SaskPower has selected that method or methods.

Response:

a) Vegetation management schedule of costs

Operating, maintenance and administration
Vegetation Management

(in millions)	Actual 2022-23	Actual 2023-24	Actual 2024-25	Forecast 2025-26	Forecast 2026-27
TOTAL OM&A	**$25**	**$25**	**$24**	**$29**	**$29**

b) Processes:

SaskPower employs the principles of Integrated Vegetation Management (IVM) to control vegetation along its transmission and distribution right of ways. This involves developing vegetation management plans and implementing treatment activities that integrate environmental management and protection, principles of plant ecology, cost effectiveness, operational efficiency, safety, socio-economic values, and stakeholder engagement.

Treatments may include manual, mechanical, herbicide and natural biological control methods. Certified Utility Arborists are employed by SaskPower to ensure the prescriptions used for each site are tailored to the individual requirements of the area.

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2026 AND 2027 RATE APPLICATION
SRRP INTERROGATORIES

SRRP Q57 Reference: Information Technology

a) To assist the Panel in understanding changes in IT costs please provide, for each of the last three actuals years plus forecasts for 2025/26 through 2026/27, SaskPower's total IT related costs broken out into:

i. Operations and maintenance expenses
ii. Finance expenses
iii. Depreciation expenses
iv. Return on equity
v. Other

b) Please describe SaskPower's approach to cybersecurity, including how SaskPower develops and monitors its cybersecurity policies and procedures and any recent updates to those policies and procedures.

c) Has SaskPower had any cybersecurity incidents that resulted in material business interruptions or insurance claims? If so, please provide a description that can be made public of any such incidents.

Response:

a)

Technology and security

(in millions)	Actual **2022-23**	Actual **2023-24**	Actual **2024-25**	Forecast **2025-26**	Forecast **2026-27**
i. Operations and maintenance expenses	$ 103	$ 106	$ 109	$ 118	$ 123
ii. Finance charges[1]	9	8	6	7	8
iii. Depreciation Computer Development & Equipment	38	38	40	42	47
iv. Return on Equity	N/A	N/A	N/A	N/A	N/A
v. Other	-	-	-	-	-

1. Finance charges have been calculated based on the relative proportion of the asset acquisition value

b)

SaskPower employs a defence in-depth, risk based cybersecurity program overseen by Enterprise Security, with governance and accountability extending through executive leadership. Cybersecurity policies and standards are aligned with NIST and ISO based control frameworks and, where applicable, comply with NERC CIP requirements for Bulk Electric System assets. Policy development and updates are informed by internal and third party risk assessments, audit findings, threat intelligence, and lessons learned from both exercises and real world incidents. SaskPower maintains continuous security monitoring capabilities across its IT environment, supported by a centralized security operations function, and conducts regular tabletop and operational incident response exercises. Recent enhancements to the program include updates to enterprise and CIP aligned incident response plans, expanded monitoring and detection capabilities, and strengthened second line risk governance to address evolving cyber threats and increasing reliance on cloud based and interconnected digital services.

c)

SaskPower has not experienced a cybersecurity incident that resulted in a material business interruption or an insurance claim.

SRRP Q58 Reference: Tax Expense

a) Please provide a table showing the detailed calculation of SaskPower's corporate capital tax obligation for the three most recent actual years and forecasts for the test years.

Response:

(in millions)	Actual **2022-23**	Actual **2023-24**	Actual **2024-25**	Forecast **2025-26**	Forecast **2026-27**
Equity/surpluses	$ 2,756	$ 2,967	$ 3,075	$ 2,959	$ 3,227
Loans and advances	771	909	807	750	693
Reserves	332	245	555	586	582
Indebtedness	6,341	6,690	7,767	8,657	9,459
Excess of net book value and undepreciated capital cost	(1,269)	(1,242)	(1,531)	(1,305)	(1,350)
Total Paid up Capital	8,931	9,569	10,673	11,647	12,611
Less: Total exemptions and allowances	(21)	(21)	(22)	(22)	(22)
Total taxable Paid Up Capital	8,910	9,548	10,651	11,625	12,589
Tax rate	0.006	0.006	0.006	0.006	0.006
Total Corporate Capital Tax	**$ 54**	**$ 57**	**$ 64**	**$ 70**	**$ 76**

SRRP Q59 Reference: Other Expenses

Please provide a break-out of SaskPower's Other expense category including Asset Disposals, Asset Retirements, Foreign exchange (if any), and Environmental Expenses for each of the five most recent actual years and forecasts for 2025/26 through 2026/27.

Response:

The following table provides other expense actuals for the 2020-21 through 2024-25 years and forecasts for 2025-26 and 2026-27:

Other Expenses

	Actual **2020-21**	Actual **2021-22**	Actual **2022-23**	Actual **2023-24**	Actual **2024-25**	Forecast **2025-26**	Forecast **2026-27**
Gain/loss on asset retirements	$ 23	$ 18	$ 9	$ 19	$ 18	$ 18	$ 18
Gain/loss on asset disposal	9	8	16	16	17	18	19
Inventory adjustments	3	7	6	-	9	4	5
Settlement claims	(37)	-	16	-	1	-	-
Environmental expense	6	3	28	3	7	8	11
TOTAL OTHER EXPENSES	**$ 4**	**$ 36**	**$ 75**	**$ 38**	**$ 52**	**$ 48**	**$ 53**

SRRP Q60 Reference: Debt and Equity

a) Please provide a schedule showing SaskPower's actual and forecast capital structure (long-term debt; short-term debt, equity, other sources of financing) for the three most recent years of actuals and forecasts for the test years.

b) Please provide the calculation of the operating return on equity percentage for each the three most recent years of actuals and forecasts for the test years showing;

   i. the calculation of the operating income
   ii. the calculation of the equity component of SaskPower's total capital structure and the equity component of ratebase.

c) Please confirm the current borrowing limit for SaskPower pursuant to the Power Corporation Act.

d) Please provide SaskPower's actual unused credit capacity at the most recent actual year and forecasts for 2025-26 and 2026-27.

e) Has SaskPower received any equity advances or repayments since the time of the last rate application? If so, please quantify and describe the circumstances associated with the equity advances or repayments.

f) Please provide a table comparing SaskPower's debt ratio with other peer Canadian utilities for the most recent actual years available.

Response:

a)

Capital Structure							
	Actual	2022-23 rate application	Actual	2022-23 rate application	Actual	Forecast	Forecast
(in millions)	**2022-23**	**2022-23**	**2023-24**	**2023-24**	**2024-25**	**2025-26**	**2026-27**
Long-term debt	$ 7,068	$ 6,758	$ 7,647	$ 7,002	$ 8,468	$ 9,454	$ 10,457
Short-term debt	790	836	910	876	809	1,109	1,259
Lease liabilities	903	902	850	848	984	944	893
Total debt	$ 8,761	$ 8,496	$ 9,407	$ 8,726	$ 10,261	$ 11,507	$ 12,609
Debt retirement funds	717	786	799	867	931	984	1,121
Cash and cash equivalents	192	10	374	10	50	44	53
Total net debt	$ 7,852	$ 7,700	$ 8,234	$ 7,849	$ 9,280	$ 10,479	$ 11,435
Retained earnings	2,071	2,265	2,237	2,341	2,313	2,166	2,245
Equity advances	593	593	593	593	593	593	593
Total Capital	$ 10,516	$ 10,558	$ 11,064	$ 10,783	$ 12,186	$ 13,238	$ 14,273
Percent debt ratio	74.7%	72.9%	74.4%	72.8%	76.2%	79.2%	80.1%

b)

Return on equity (ROE) calculation

Return on equity = (net income)/(average equity), where equity = (retained earnings + equity advances)

(in millions)	Actual **2022-23**	Actual **2023-24**	Actual **2024-25**	Forecast **2025-26**	Forecast **2026-27**
Total revenue	3,067	3,379	3,254	3,293	3,526
Total expense	3,239	3,195	3,178	3,440	3,447
Net Income	$ (172)	$ 184	$ 76	$ (147)	$ 79
Equity					
Retained earnings	2,071	2,237	2,313	2,166	2,245
Equity advances	593	593	593	593	593
Total equity	$ 2,664	$ 2,830	$ 2,906	$ 2,759	$ 2,838
Average equity	$ 2,748	$ 2,747	$ 2,868	$ 2,833	$ 2,799
Return on equity	(6.3%)	6.7%	2.6%	(5.2%)	2.8%

c) SaskPower's current borrowing limit is $14 billion as of May 2025. Previously, it was $10 billion.

d) SaskPower's actual unused credit capacity for 2024-25 was $0.6 billion (legislated total borrowing authority was $10 billion), 2025-26 $3.3 billion, 2026-27 $2.2 billion.

e) SaskPower has not had any equity advances or repayments since the last rate application.

f) Please refer to the following table for a comparison of SaskPower's per cent debt ratio compared to other Canadian utilities:

GOVERNMENT/VERTICALLY INTEGRATED UTILITIES

Per cent debt ratio — 2024-25 vs 2023-24

RANK		2024-25	2023-24	+/-	TREND
1	NF & LB Hydro	63.3%	60.0%	3.3%	↑
2	Hydro QC	66.5%	65.8%	0.7%	↑
3	**SaskPower**	76.2%	74.4%	1.8%	↑
4	BC Hydro	80.0%	79.8%	0.2%	↑
5	MB Hydro	87.5%	87.3%	0.2%	↑
6	NB Power	91.6%	91.4%	0.2%	↑

Source: Recalculated using publicly available financial information

SRRP Q61 Reference: Productivity and Efficiency

a) Please discuss how SaskPower budgets for and tracks productivity and efficiency improvements in its operating budgets.

b) Please provide any quantifiable information SaskPower maintains on tracking the long-term savings of productivity and efficiency programs.

Response:

a) Tracking productivity and efficiency improvements:

SaskPower incorporates productivity and efficiency improvements directly into its budgeting and financial management processes through a combination of proactive planning, collaborative discussions, and ongoing tracking.

1. Embedding Efficiency Opportunities in the Budget Cycle
   Throughout the year, discussions take place with Vice Presidents and Directors to identify potential efficiencies within their business units. These conversations focus on understanding operational pressures, emerging risks, and opportunities to either reduce or avoid costs. Efficiency opportunities may arise from:

   - Vacancy management when positions can remain unfilled without compromising service levels.
   - Adjusting or deferring planned work where operational risk remains manageable.
   - Cost reduction initiatives, such as process improvements or alternative ways of delivering work.

   Each potential efficiency is assessed not only for financial impact but also for risk, ensuring that any reductions are sustainable and do not adversely affect reliability, safety, or strategic objectives.

2. Tracking Efficiencies Throughout the Year
   SaskPower maintains a dedicated tracking spreadsheet that records all efficiency initiatives by business unit, enabling visibility and accountability across the organization. Efficiencies are grouped into two primary categories:

   - Compensation efficiencies, such as vacancy management or organizational structure adjustments.
   - Non-compensation efficiencies, such as reduced materials, consulting, travel, or discretionary spending.

   The tracking also includes items that were not part of the initial budget but were consciously avoided during the year to prevent cost overruns. By monitoring avoided costs as well as budgeted efficiencies, SaskPower ensures a complete picture of how the organization manages spending and responds to emerging pressures.

b) Quantifiable tracking of long-term savings

For tracking long-terms savings, SaskPower compares it's 10-year OM&A projections from it's 2016 business plan (the year SaskPower shifted from calendar year reporting to fiscal year reporting) to the actual amount spent in each of those years. Since 2016, actual OM&A expenditures were $888 million less than what was projected in 2016.

SRRP Q62 Reference: Safety

a) Please provide the five most recent years of actual lost-time injury frequency rates, lost-time injury severity rates, and recordable injury frequency rates for SaskPower and peer utilities.

b) Please provide an overview of how SaskPower's workplace safety programs and how SaskPower responds to changes in safety rates

Response:

a) The tables below include the five most recent years of actual lost-time injury frequency rates, lost-time injury severity rates, and recordable injury frequency rates compared to our peer Electricity Canada utilities:

Lost-time Injury Frequency Rate (LTIFR)	SaskPower LTIFR	EC Group 1 composite average
2020	0.50	0.55
2021	0.39	0.64
2022	0.93	0.76
2023	0.52	0.64
2024	0.29	0.56

Lost-time Injury Severity Rate (LTISR)	SaskPower LTISR	EC Group 1 composite average
2020	19.2	14.9
2021	4.7	18.2
2022	19.3	15.2
2023	9.4	17.8
2024	5.7	14.5

Recordable Injury Frequency Rate (RIFR)		
	SaskPower RIFR	CEA Group 1 composite average
2020	2.7	2.7
2021	2.3	2.6
2022	2.9	1.7
2023	2.7	1.5
2024	2.0	1.4

b)

Currently, each safety incident results in an LTI, require a director level meeting where a lesson learned is pulled out and shared across the organization where applicable. Health and Wellness office works with each injured person to ensure safe and efficient return to work. This occurs on case-by-case basis. Finally, a report is sent to the Executives and Board of Directors on all LTI frequency and severity.

To continue to address the Lost Time Injury Rate and Lost Time Severity Frequency, SaskPower, through continuous improvement strategy, is implementing a new approach called Energy Based Safety. This approach allows our workforce to focus on high-risk energies that may create life altering or life ending situations. Incorporating Energy Based Safety into our Safety Management processes allow our operations to proactively mitigate risk and identify high energy hazards by implementing direct controls applicable to the identify hazard to prevent occurrence or re-occurrence of events that negatively impact our organization.

Through this new approach, we are aligning our Safety Management System to Energy Based Safety improving how we analyze data, monitor field operations using multiple measuring methods (i.e. Inspections, Work Observations, and Risk Assessment/Hazard Identification) and measuring the effectiveness of corrective actions. Using these measuring methods to monitor safety performance allows SaskPower to proactively address issues and to mitigate and/or prevent Lost Time Injuries.

SRRP Q63 Reference: Wildfire Risk

a) Has SaskPower prepared a wildfire risk assessment and management plan? If so, please provide a copy. If not, please discuss how SaskPower manages its wildfire risk.

b) Please provide a table showing SaskPower's spending for each of the last five actual years and forecasts for 2025-26 and 2026-27 on:

   i. wildfire response (i.e. responding to specific wildfire events)
   ii. wildfire risk mitigation plans or programs

c) Please provide an estimate of the amount of wildfire response spending in part (b) that was covered by insurance.

d) What proportion of SaskPower's existing transmission infrastructure is wood compared to steel or other materials.

e) Please discuss how wildfire risk has influenced how SaskPower plans its transmission capital program.

Response:

a) Has SaskPower prepared a wildfire risk assessment and management plan? If so, please provide a copy. If not, please discuss how SaskPower manages its wildfire risk.

Yes. SaskPower prepares and manages an annual comprehensive Wildfire Prevention & Preparedness Plan ("Plan").

Effective 2015, Saskatchewan adopted *The Wildfire Act* as the legal framework for the prevention, management, and control of wildfires in the province, ensuring public safety and sustainable resource management. For more information related to *The Wildfire Act*, please refer to these public resources:

- New Wildfire Legislation Now in Effect | News and Media | Government of Saskatchewan
- SS 2014, c W-13.01 | The Wildfire Act | CanLII

SaskPower's 2025 Plan functions as both a wildfire risk assessment and a management framework. Designed to meet the requirements of the provincial legislation, the Plan applies to all SaskPower assets and activities located within wildfire management areas.

Risk Assessment Approach

Wildfire risk is assessed through a combination of:

- Identification of ignition sources associated with SaskPower operations (generation, stations, construction, maintenance, and transmission/distribution rights-of-way).
- Evaluation of fuel hazards surrounding facilities, stations, camps, and rights-of-way.
- Daily, site-specific Hazard/Aspect & Risk Assessments (HARA) completed before work begins during wildfire season.

- Ongoing monitoring of provincial wildfire danger ratings issued by the Saskatchewan Public Safety Agency (SPSA).

This multi-faceted approach allows SaskPower to assess both static risks (asset location, construction type, surrounding fuels) and dynamic risks (weather conditions, fire danger ratings, operational activities).

Risk Management Framework

Wildfire risk is managed through an integrated prevention, mitigation, and preparedness framework that includes:

- Ignition prevention measures for equipment, vehicles, stations, and operations.
- Fuel hazard management around facilities, stations, camps, and along rights-of-way.
- Vegetation management programs based on Integrated Vegetation Management (IVM) principles.
- Operational controls such as work restrictions or shutdowns during periods of high or extreme fire danger when directed by SPSA.
- Coordination with SPSA and participation in provincial emergency response structures, including the Provincial Emergency Operations Centre when required.

Together, these measures are intended to reduce the likelihood of wildfire ignition, limit fire spread should an ignition occur, and ensure a coordinated response that prioritizes safety and system reliability.

b) Please provide a table showing SaskPower's spending for each of the last five actual years and forecasts for 2025-26 and 2026-27 on:

i. wildfire response (i.e. responding to specific wildfire events)

ii. wildfire risk mitigation plans or programs

The following is a table outlining the historical and forecasted wildfire costs:

Wildfire Costs ($ millions)

Fiscal Year (FY)	Wildfire Mitigation	Wildfire Response	Wildfire Capital Re-Build Projects	Total
FY21 - Actual Costs	13.3	0.2	-	**13.5**
FY22 - Actual Costs	14.4	0.6	-	**15.1**
FY23 - Actual Costs	14.1	0.1	-	**14.3**
FY24 - Actual Costs	11.6	0.6	-	**12.2**
FY25 - Actual Costs	4.0	1.1	-	**5.1**
FY26 - Forecasted Costs	5.1	5.0	8.3	**18.3**
FY27 - Forecasted Values	12.8	-	-	**12.8**
7-Year Projected Total	**75.4**	**7.5**	**8.3**	**91.2**

Notes:

- Costs attributed to wildfire mitigation activities include items such as vegetation management in wildfire regions, the installation of fire-retardant wood pole wrap and the application of fire retardant.
- Costs attributed to wildfire response include the costs incurred to respond and recover to wildfire events involving SaskPower infrastructure.
- Costs attributed to the capital re-build phase after a wildfire event, including items such as establishing a high-load move corridor and rebuilding the infrastructure in communities.
- FY26 forecasted costs are as of January 31, 2026.
- Wildfire response and capital rebuild costs are not projected into future budgets.

c) Please provide an estimate of the amount of wildfire response spending in part (b) that was covered by insurance.

SaskPower did not receive any insurance coverage for costs associated with wildfire response or wildfire risk mitigation plans or programs during the past five years, nor are such costs anticipated to be covered for the forecast periods 2025–26 and 2026–27.

d) What proportion of SaskPower's existing transmission infrastructure is wood compared to steel or other materials.

Approximately 72% of SaskPower's existing transmission infrastructure is wood based. The remaining 28% consists of steel and other materials.

Please note that all new transmission lines being constructed in wildfire zones use steel structures.

e) Please discuss how wildfire risk has influenced how SaskPower plans its transmission capital program.

In addition to collaborating closely with the Saskatchewan Public Safety Agency (SPSA) and adhering to *The Wildfire Act*, SaskPower focuses on the following risk mitigation efforts related to its transmission capital program:

- All new transmission lines being constructed in wildfire zones use steel structures.
- Installing a fire-retardant wrap on existing wood transmission poles within the wildfire zones to protect poles from typical fire damage, especially for lines that feed remote communities in the provincial forest.
- Strategically increasing materials, such as spare structures, conductors and other hardware, stored in these zones. This proactive measure leads to faster recovery when crews can safely perform repairs or rebuilds of damaged infrastructure.
- Where possible for new transmission lines, SaskPower considers routing options around wildfire areas by routing through clear-cut zones, bedrock zones, or other landscape options.
- SaskPower has developed a systematic LiDAR (Light Detection and Ranging) data collection & processing system for vegetation management and wildfire preparedness, contributing to vegetation management program planning and growth forecasting.
- Other wildfire mitigation considerations include
    - Vegetation free zones around transmission structures to limit fuel availability and the associated potential for wildfire damage,
    - Breaks in windrows along transmission lines to help impede wildfire progression.

As SaskPower focuses on long-term transmission investments as outlined in the Government of Saskatchewan's "Strengthening Saskatchewan Grid: Transmission to Power Communities and Growth" report (https://www.saskatchewan.ca/-/media/news-release-backgrounders/2026/feb/transmission-implementation-strategy-5422.pdf), mitigating wildfire risk will be embedded in the three priorities of:

1. Reinforcing the existing grid to support reliability, safety and load growth across the province, and
2. Developing new transmission infrastructure in the far north, and
3. Expanding interconnections with neighbouring provinces and U.S. markets to improve resilience and create more opportunity for power imports and exports.

SRRP Q64 Reference: Capital Program

a) Please describe any changes to SaskPower's capital planning process since the time of the last rate application in particular with respect to:

i. how project scopes and budgets are developed;
ii. the approval process for SaskPower's capital plan;
iii. how SaskPower paces and prioritizes its capital plans (for example, does SaskPower develop a high-level capital spending envelope and then prioritize projects within that envelope); and
iv. how SaskPower manages and monitors the delivery of its capital projects including project reporting, variance analysis, and quality assurance in the delivery of each capital project.

Response:

i. *how project scopes and budgets are developed;*

SaskPower has put considerable effort into advancing the input that the execution teams have in shaping project scope during the planning process which serves to increase the achievability of projects. SaskPower's estimating team continues to drive alignment to industry best practice around the development and allocation of risk based contingency funding and the alignment of estimate classification and accuracy to the maturity level of project deliverables.

ii. *the approval process for SaskPower's capital plan;*

There has been no significant changes to this approval process since the time of the last rate application. SaskPower's capital plan approval process continues to follow SaskPower's Business Plan approval process at a corporate level and then follows SaskPower's Governance Manual for individual capital project approvals.

iii. *how SaskPower paces and prioritizes its capital plans (for example, does SaskPower develop a high-level capital spending envelope and then prioritize projects within that envelope); and*

Capital plans are paced and prioritized via SaskPower's Asset Management teams. The capital work required to evolve SaskPower's system, support economic development, and maintain SaskPower's existing fleet assets is assessed and aligned as closely as possible to the execution capacity of project delivery teams. SaskPower's delivery model includes a number of formal phase gates which provide an opportunity to reassess a projects priority within the capital portfolio in real time.

iv. *how SaskPower manages and monitors the delivery of its capital projects including project reporting, variance analysis, and quality assurance in the delivery of each capital project.*

SaskPower has centralized the monitoring of its capital portfolio via the Corporate Project Management Office. This department is responsible for the ongoing development of industry aligned delivery standards as well as the independent evaluation of portfolio progress and the tools necessary to ensure transparency into these metrics are available. SaskPower has implemented a Portfolio Board which governs the development, authorization and execution of the ongoing Capital Portfolio. This board ensures that capital delivery remains in alignment with corporate priorities and serves to support portfolio prioritization efforts.

SRRP Q65 Reference: Capital Program

a) Please expand the capital spending table provided on page 30 of the application to include the most recent five years of actual spending.

Response:

a) The following capital spending table includes actual results for the most recent five years:

Capital spending

(in millions)	Actual 2020-21	Actual 2021-22	Actual 2022-23	Actual 2023-24	Actual 2024-25	Forecast 2025-26	Forecast 2026-27
CAPITAL SUSTAINMENT INVESTMENT							
Generation	$ 125	$ 113	$ 100	$ 155	$ 182	$ 224	$ 155
Transmission	42	89	75	92	90	140	139
Distribution	99	137	145	163	177	219	304
Other	100	86	101	110	106	105	112
	366	425	421	520	555	688	710
GROWTH & COMPLIANCE INVESTMENT							
Generation	100	294	233	389	590	728	487
Transmission	35	39	121	39	51	150	359
Distribution	14	15	15	16	22	17	20
Customer Connects	137	142	183	177	192	242	191
	286	490	552	621	855	1,137	1,057
TOTAL STRATEGIC & OTHER INVESTMENT	41	47	92	72	87	114	73
Future Electricity Fund	-	-	(7)	(44)	(72)	(149)	(128)
Power Grid Renewal Grant	-	(40)	-	-	-	-	-
Other Funding	-	-	(11)	(5)	(2)	(3)	(20)
TOTAL CAPITAL SPENDING	**$ 693**	**$ 922**	**$1,047**	**$1,164**	**$1,423**	**$1,787**	**$1,692**

SRRP Q66 Reference: Capital Program

a) For each capital project or program with final costs in excess of $10 million for each of the last three actual years please provide:

i. The justification for the project (e.g. capacity or system growth requirements; infrastructure renewal; operating efficiencies/savings)
ii. the original budget allocation
iii. the final actual project direct costs
iv. capitalized interest, overheads, and other charges;
v. an explanation for any variances of more than 10% from the original budget.

Response:

Included projects/programs with total actual spend greater than $10M in FY2023, FY2024 and FY2025.

Annual Programs

Program	Fiscal year	Justification	Approved CPA (thousands)	Total annual costs (thousands)
Programs				
Program - Distribution Customer Connects	2023	Customer Connect	$ 126,500	$ 127,290
Program - Distribution Customer Connects	2024	Customer Connect	160,000	150,638
Program - Distribution Customer Connects	2025	Customer Connect	161,200	158,965
LN Rural Rebuild & Improvement	2023	Sustainment Investment	34,600	36,288
LN Rural Rebuild & Improvement	2024	Sustainment Investment	48,000	45,603
LN Rural Rebuild & Improvement	2025	Sustainment Investment	50,000	50,578
LN Underground Primary Cable Mitigation	2023	Sustainment Investment	12,000	10,508
LN Underground Primary Cable Mitigation	2025	Sustainment Investment	15,304	10,597
LN Urban Core Infrastructure Improvements	2023	Sustainment Investment	10,850	10,603
LN Urban Core Infrastructure Improvements	2025	Sustainment Investment	14,000	12,538
LN Wood Pole Replacements	2024	Sustainment Investment	14,000	14,187
LN Wood Pole Replacements	2025	Sustainment Investment	20,000	19,419
Joint Use Pole Replacement (New Connects)	2024	Sustainment Investment	16,000	14,437
Joint Use Pole Replacement (New Connects)	2025	Sustainment Investment	13,500	14,683
LN RUD Mitigation (Rural Underground Mitigation)	2025	Sustainment Investment	13,000	11,741
LN Rural Economic Rebuild	2025	Growth, Compliance & Resiliency	14,000	13,186
Vehicles & Equipment	2023	Sustainment Investment	14,900	15,015
Vehicles & Equipment	2024	Sustainment Investment	21,800	21,696
Vehicles & Equipment	2025	Sustainment Investment	26,700	25,959

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Projects

Project	Justification	Approved CPA at March 31, 2025 (thousands)	Total costs at March 31, 2025 (thousands)
Generation			
ER/YH GE GT/COMP Replacement	Sustainment Investment	$ 32,000	$ 27,053
QEC U4-9 GT 2ND HGPI & MI (96,000 & 128,000 EOH)	Sustainment Investment	30,000	26,752
ER/YH 2nd Spare Gas Turbine PD Engine	Sustainment Investment	19,500	17,511
QED U10-12 GT 1st HGPI & MI	Sustainment Investment	14,874	12,752
Chinook Gas & Steam Turbine LTSA	Sustainment Investment	25,510	15,511
Chinook Power Station	New Generation	680,500	591,140
Cory Gas & Steam Turbine LTSA	Sustainment Investment	108,700	29,775
ER/YH Air Inlet Preheat	Sustainment Investment	30,210	25,592
ER/YH GT 1ST Major Overhaul	Sustainment Investment	50,821	14,638
Landis Unit #1 Life Extension	Sustainment Investment	38,240	18,562
QED Gas Turbine Generator Refurbishments	Sustainment Investment	24,000	19,417
CC Life Extension	Sustainment Investment	83,000	46,630
EBC Unit 1 to 6 Life Extension	Sustainment Investment	300,000	227,220
H&R Public Safety & Security Upgrades	Sustainment Investment	16,545	14,292
Aspen Power Station	New Generation	1,690,836	499,808
Ermine Unit 3 & Yellowhead Unit #4	New Generation	379,000	343,903
Great Plains Power Station	New Generation	808,097	750,716
Transmission			
SUB - Sutherland Conversion - 138kV - New	Growth, Compliance & Resiliency	$ 18,670	$ 17,668
LN - S1E Rebuild 72kV MOD	Sustainment Investment	16,889	15,915
LN - Y1P 138kV Line Sustainment MOD	Sustainment Investment	27,593	24,874
LN Wolverine to BHP Jansen - 230kV	Customer Connect	46,010	36,696
LN Pasqua to Rowatt-230kV	Growth, Compliance & Resiliency	85,062	78,287
SB Substations Remote Monitoring Stage 3-72-25 kV-Mod	Growth, Compliance & Resiliency	14,446	14,548
SS Beechy Area Reinforcement 230-25kV	Growth, Compliance & Resiliency	18,795	16,080
STN Rowatt Station Development - 230kV	Growth, Compliance & Resiliency	25,080	24,821
LN Transmission Switch Upgrades	Sustainment Investment	10,625	10,255
STN 2021-2023 Relay Replacement	Sustainment Investment	15,970	16,013
LN Bekevar Wind Interconnection 200 MW-230kV	Customer Connect	18,326	15,425
LN Great Plains CCGT Generation Interconnection - 230kV	Customer Connect	16,903	16,057
LN IF56 to Foran - 138kV	Customer Connect	121,990	14,666
SS SPP to SPC 500 MW TSR - 230kV	Growth, Compliance & Resiliency	207,703	32,813
STN Battery Energy Storage System-13.8kV	Growth, Compliance & Resiliency	35,666	34,609
EMS Upgrade	Sustainment Investment	16,486	14,085
LN GL7 72kV Line Sustainment	Sustainment Investment	32,756	27,901
LN TD4 Rebuild-72kV	Sustainment Investment	45,455	40,538
LN W3B-BL Line Sustainment-115kV	Sustainment Investment	31,883	10,792
STN Boundary Dam SS Improvements	Sustainment Investment	10,300	10,316
TC5 Rebuild-72kV	Sustainment Investment	70,220	22,341
Corporate Services			
Head Office Refurbishment Program	Sustainment Investment	$ 129,000	$ 128,153
Tisdale Maintenance Hub	Sustainment Investment	11,000	10,643
Nipawin Maintenance Outpost	Sustainment Investment	10,750	10,523
Saskatoon Maintenance Center Renovation	Sustainment Investment	63,000	27,917
Regina Operations and Maintenance Complex	Strategic & Other Investment	280,000	212,140
Technology			
Clicksoft Replacement	Sustainment Investment	$ 11,406	$ 11,260
JUNO SAP Program	Sustainment Investment	26,292	21,684

SRRP Q67 Reference: Capital Program

a) With reference to the rural rebuild and improvement program, please discuss how SaskPower identifies and prioritizes the lines to be replaced.

Response:

SaskPower's rural system is comprised of both overhead pole lines and underground cable. Infrastructure replacement is prioritized based on a combination of risk factors including public safety, customer service reliability, and ability to serve customer load. Asset inspection and condition assessments are used to assess these risk factors. Wood pole inspections focus on assessing any damages, determining the remaining pole strength, and verifying safe ground clearances. SaskPower inspects distribution wood poles greater than or equal to 30 years of age once every six years. Underground cable condition assessments focus on assessing the integrity of the insulation that surrounds the conductor and identifying any impedance irregularities that may be problematic. Due to the extremely large fleet of underground cable, statistical samples are tested to estimate the condition of all cables in the test area that are of the same vintage.

SRRP Q68 Reference: Capital Program

a) With respect to the smart meter deployment described on page 9 of SaskPower's 2024-25 annual report, please provide an update on how many smart meters have been installed and when SaskPower expects the roll-out will be complete.

b) Does SaskPower have any plans to develop the back-end systems that would be necessary to support demand response or time-of-use rates for residential and small commercial customers? Please discuss.

Response:

a) It was previously reported on Page 9 of the 2024-2025 SaskPower Annual Report that 21% of smart meters were deployed. As of February 17, 2026, SaskPower has deployed 46% of the smart meters it expects to deploy and is targeting full deployment by December 2028.

b) The backend systems are ready to be configured to produce demand response and time of use rates for residential and small commercial customers. This configuration effort would need to be projectized and delivered. It is expected that this could be completed within a timeframe of 5-6 months once initiated.

SRRP Q69 Reference: Customer Connects

a) Please provide SaskPower's customer connect spending by customer class for each of the last three actual years and forecasts for 2025-26 and 2026-27.

b) Please describe any updates or changes to SaskPower's customer connect policies since the time of the 2022 and 2023 rate application.

Response:

a) The following table provides actual customer connect spending by customer class for 2022-23 through 2024-25 and forecasted spending for 2025-26 and 2026-27.

Customer connect spending by customer class

(in millions)	Actual **2022-23**	Actual **2023-24**	Actual **2024-25**	Forecast **2025-26**	Forecast **2026-27**
Residential	$ 38	$ 36	$ 46	$ 49	$ 50
Farm	24	22	25	22	22
Commercial	38	47	52	56	57
Oilfield	29	46	36	43	43
Total Distribution	129	151	159	170	172
Total Transmission	54	26	33	72	19
Total customer connect spending	$ 183	$ 177	$ 192	$ 242	$ 191

b) There have been no changes to SaskPower's customer connect policies since the 2022 and 2023 rate application.

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SRRP Q70 Reference: Load Forecasts

a) Please discuss any changes to assumptions, methodology, or explanatory variables used for the load forecasts and customer count forecasts for each major customer class since the previous rate application, including any changes affecting input data.

b) Please discuss any alternative assumptions, methods, and explanatory variables that were tested by SaskPower for the load forecasts or customer count forecasts and why these were not chosen for the final forecasts.

Response:

a) SaskPower has made the following changes to its load forecasting methodology since the previous rate application:

<u>Mass Market Forecast:</u>

1. Shifted from calculating weather normals based on 30 years of historical data to 15 years of historical data.
2. Added a commercial statistically adjusted end use model as an input to the commercial sector forecast.
3. Added a farm and commercial EV forecast into these sectors.
4. Streetlights have been fully converted to LED so no further adjustments have been made to their forecast to reflect future decreases. The forecast already contains the drop in consumption.
5. Mass market energy forecasts are now determined monthly, rather than annually, following Itron's 2024 load forecast review. Variables in these forecasts have also shifted to a monthly basis to better align with UPC's monthly trends. This change applies to the Residential, Farm, and Commercial forecasts.
6. The Oilfield energy forecast was previously done on a regional basis and has now shifted to a provincial level.
7. Residential customer forecast shifted from an exponential smoothing model to a regression model. Commercial customers have shifted from a regression model to an exponential smoothing model. Oilfield was previously done as a bottom up that combined regression and exponential smoothing models; this has now shifted to a total oilfield customer forecast done as an exponential smoothing model.

8. PV forecasts have also been segregated into farm, commercial, oilfield and internal use as new customers have come online.
9. Residential price sensitivity inputs into the statistically adjusted end use model have shifted from using a household forecast to non-farm households and a population index.
10. Commercial energy forecast has shifted from a sales model using commercial customers as the main driver to using commercial UPC based on the statistically adjusted end use model as the main driver.
11. Farm energy forecast has also shifted from being a sales model using weather and the statistically adjusted end use model to a UPC model with the main drivers also being weather and statistically adjusted end use variables interacted together.
12. Streetlight sales have changed from being based on residential customer quantity forecast to the commercial customer quantity forecast.
13. Streetlight customer forecast has shifted from being based on the commercial customer quantity forecast to being based on a bulb count forecast produced within SaskPower models.

Large Customer Forecast:

1. SaskPower has largely kept its customer forecast methodology the same as before, except for adding a probability decision matrix to better estimate speculative expansions and new entrants. The matrix combines factors like technical and project feasibility, financial viability, supply chain impact, stakeholder support, and market conditions to determine probabilities.

b) SaskPower does not keep records of every model that is evaluated. Every year our mass market models are tested in Metrix ND with alternative variables and methods. These are selected or discarded based on their fit with the historical data based on professional judgement and model statistics. Some commonly reviewed model statistics include:

- R-Squared
- Adjusted R-Squared
- AIC
- BIC
- Mean Squared Error
- Standard Error of Regression
- MAD

- MAPE
- Durbin Watson

The resultant forecast is also evaluated based on professional judgement and only kept if the forecast matches expectation. Sales and UPC models are likewise tested with alternative econometric data. If those variables do not make sense using professional judgement and model statistics for the historical data, they are likewise discarded and alternative data is sought. The UPC and sales forecasts are also evaluated based on historical data and with professional judgement. Below is a list of assumptions and variables that were tested by SaskPower for the load forecast used in this application and reasons for their inclusion or exclusion:

1. The evaluation of both regression and exponential smoothing models for customer forecasts in Residential, Farm, Commercial, Oilfield, and Streetlight categories, using statistical fit and professional judgment. For Residential and Farm, regression models were chosen due to superior fit; for Oilfield and Commercial, exponential smoothing was preferred. For Streetlights, a regression model was selected after exponential smoothing was tested but not adopted.

2. In regression models for customer forecasts, we tested various economic variables such as households, non-farm households, farm households, population, and persons per household. The final model used households for residential customers, farm households for the farm forecast, and streetlight bulb count for streetlights, based on their statistical significance.

3. For oilfield forecasts we tested intensities (kwh/m3) whether they are total fluid (including water and oil) draw or just oil draw from the ground. We select this based on statistical fit and professional judgement. We also tested Oil and Gas GDP data to see if they are significant with regards to oilfield production and intensities, but they were rejected due to poor results. Oil intensities were selected for this forecast as they are the most statistically significant.

4. The Residential UPC model was changed from using adjusted lighting data to stock lighting data as they match historical weather normalized UPC.

SRRP Q71 Reference: Load Forecasts

a) For each of the ten most recent actual years, please provide a schedule showing the actual sales for each major customer group and the sales forecast from the load forecast immediately preceding the actual year. Please also include forecast and actual line losses and station service. Comment on any material variances between actuals and forecasts.

b) Please provide a table showing 10 years of electricity sales and customer account forecasts from the load forecasts used to support each of the last three rate applications. The 10 years of forecasted data should start from the first test year of each Rate Application (t+10).

c) Please comment on the steps SaskPower takes to verify large-scale industrial and commercial customer load forecasts including for potential new customers.

d) With reference to the media reports of a planned data centre near Regina (see: https://www.cbc.ca/news/canada/saskatchewan/bell-ai-data-centre-regina-9.7083484) please discuss:

   i. Is SaskPower aware of the approximate capacity and energy that will be required by the data centre?

   ii. Does SaskPower have sufficient generation and transmission capacity available or would this project require new infrastructure?

   iii. Is SaskPower aware of whether or not there were any federal, provincial or municipal government incentives offered to the developer?

Response:

a) Please see excel spreadsheet, "Q71", tab "Part A". Over the past ten years, SaskPower's annual forecast variances have averaged (0.55%) for energy sales and (1.26%) for total energy requirements. However, predicting system losses has remained difficult; these losses have differed from forecasts by an average of (11.03%). SaskPower mainly attributes this to differences in timing between when energy is generated and when it is recorded as sold, which is influenced by billing cycles. With greater adoption of AMI technology, SaskPower expects that loss forecasting accuracy will improve significantly.

b) Please see excel spreadsheet, "Q71", tab "Part B".

c) Potential large industrial loads are added to the forecast based on the stage of the interconnection process along with other measures such as technical feasibility, project feasibility, financial viability, supply chain impact, stakeholder support, and market conditions. A probability of proceeding is assigned using a decision matrix that incorporates analysis of the quantitative and qualitative measures above.

d) i) SaskPower is aware of the data centre project but the capacity and energy that will be required has not been confirmed and is still being negotiated.

ii) Although the project is still under negotiation, SaskPower will only offer excess capacity for the data centre project, and the transmission costs would be minimal as the project's location is very close to a substation.

iii) SaskPower not aware of the developer's financial arrangements with respect to this project.

SRRP Q72 Reference: Load Forecasts

a) Please provide the forecasted and top three actual system winter and summer peaks for each of the five most recent actual years.

b) Please comment on any material variances between actual and forecast peaks for the most recent five years as well as how any changes in methodology to the current system peak demand forecast will improve forecast accuracy.

c) Please provide the generation capacity by fuel type used to meet the top actual system winter and summer peaks.

d) Please elaborate on the statement on page 10 of the application that "Most of the increase is related to Power customer class sales, especially in the mining, pipeline, and refinery sectors" and quantify the changes in peak demand by customer type for each of the last three years and forecasts for 2025/26 through 2026/27.

Response:

a) Please see the table below containing the requested peaks (interval (60min)):

Top 3 Winter and Summer Peaks

		Actual		Forecast		Difference	
		Winter	Summer	Winter	Summer	Winter	Summer
2024	1	3,817.9	3,608.9	3,920.0	3,677.0	-102.1	-68.1
	2	3,817.7	3,585.8	3,912.0	3,639.0	-94.3	-53.2
	3	3,776.7	3,574.9	3,888.0	3,630.0	-111.3	-55.1
2023	1	3,625.4	3,552.2	3,925.0	3,682.0	-299.6	-129.8
	2	3,611.6	3,542.2	3,916.0	3,647.0	-304.4	-104.8
	3	3,585.5	3,498.1	3,890.0	3,641.0	-304.5	-142.9
2022	1	3,786.6	3,513.9	3,954.0	3,656.0	-167.4	-142.1
	2	3,727.0	3,505.3	3,944.5	3,642.0	-217.5	-136.7
	3	3,716.2	3,461.7	3,919.7	3,607.0	-203.5	-145.3
2021	1	3,870.4	3,539.3	3,724.0	3,382.0	146.4	157.3
	2	3,778.4	3,503.7	3,681.0	3,344.0	97.4	159.7
	3	3,775.1	3,488.3	3,659.0	3,325.0	116.1	163.3
2020	1	3,695.1	3,417.2	3,902.0	3,535.0	-206.9	-117.8
	2	3,680.9	3,391.1	3,890.9	3,524.0	-210.0	-132.9
	3	3,657.9	3,380.6	3,874.5	3,519.0	-216.6	-138.4

(

b) The main factor causing differences between forecasted and actual peaks is weather. SaskPower's forecasts plan for prolonged cold in winter and warm temperatures during summer, but customer usage patterns, especially among a few large customers, also play a significant role in affecting system peaks. Currently, the forecasting method is shifting from relying on historical coincident peak load factors to a bottom-up approach, where peaks are estimated by combining different classes and technology-specific load shapes. This modeling process is still being developed as we gather the necessary operating profiles. Advanced Metering Infrastructure (AMI) data will be essential for this work, along with accurate profiles for technologies like electric vehicles, net metering, and battery storage. This shift aligns with the main recommendation from the latest load forecast methodology review conducted by iTron.

c) The following table contains the generation capacity by fuel type used to meet the top actual system winter and summer peaks.

		Generation by Fuel Type (MW)						
Season	**Date**	**Peak (MW)**	**Hydro**	**Coal**	**Gas**	**Wind**	**Other**	**Import**
Summer	2024-07-31	3669	505	1108	1552	191	32	281
Winter	2021-12-30	3910	355	1008	1950	149	1	447

d) At the time of the forecast, there was an increase in load requests in the north of the province. There are also certain other mining projects that are set to come online outside of the north. Pipeline load continues to be a significant driver of both energy sales and peak demand. Finally, some major refinery additions were anticipated.

Forecast peaks by large customer sector are as follows:

Year	Potash	Pipeline	Pulp & Paper	Steel	Chemical	Refineries	North Mines	Misc.	Sub-Total
2022	309	453	88	98	47	83	45	101	1,225
2023	308	475	99	114	31	84	52	92	1,256
2024	383	489	97	82	47	84	52	91	1,325
2026	380	516	86	98	49	112	89	160	1,489
2027	431	511	85	97	49	111	98	168	1,550

*2025 Actuals are unavailable currently

** Sector Peaks are only done on a calendar basis

SRRP Q73 Reference: Energy Efficiency

a) Has SaskPower completed a more recent Conservation Potential Review than the 2017 Navigant report? If so, please provide a copy. If not, please discuss if and when SaskPower intends to commission an updated study.

b) With reference to the energy efficiency programs summarized in section 2.1 of the application, please provide the actual costs associated with these programs for the three most recent actual years and forecasts for 2025/26 through 2026/27 by rate class and the estimated energy and capacity savings associated with each program.

c) Please provide summary details of any other energy efficiency, demand side management, or conservation programs currently administered by SaskPower beyond those summarized in section 2.1 of the application.

Response:

a) No, SaskPower has not completed a more recent Conservation Potential Review (CPR) than the 2017 Navigant report, nor do we have a timeline for commissioning a new study.

b) **Program Costs**

	2022-23		2023-24		2024-25		2025-26		2026-27	
	Actuals	% Funded	Actuals	% Funded	Actuals	% Funded	Forecast	% Funded	Forecast	% Funded
Online Energy Assessment for Homes	$ 54,000		$ 54,000	50%	$ 54,000	100%	$ 54,000	100%	$ 50,000	50%
Energy Assistance Program	648,000	50%	2,158,000	50%	2,472,000	100%	2,315,000	100%	3,300,000	100%
Northern First Nations Home Retrofit Program	1,319,000	70%	2,883,000	70%	3,551,000	100%	4,887,000	100%	6,500,000	100%
Northern Indigenous New Homes Program							78,000	100%	500,000	50%
Energy Efficiency Discounts Program			824,000	50%	1,686,000	100%	1,467,000	100%	1,000,000	50%
Home Efficiency Retrofit Rebate Program			169,000	50%	252,000	100%	115,000	100%	90,000	50%
Commercial Energy Optimization Program (CEOP)					1,149,000	100%	2,852,000	100%	2,843,000	100%
CEOP - Custom Incentive Services			38,000	50%	15,000	100%	151,000	100%	500,000	50%
Commercial Space and Water Heater Rebate Program					-	-	1,000	100%	50,000	50%
Residential Customer Engagement					158,000	0%	205,000	100%	280,000	100%
TOTAL	$ 2,021,000		$ 6,126,000		$ 9,337,000		$12,125,000		$15,113,000	

Note: SaskPower has leveraged the Future Electricity Fund and Clean Electricity Transition Grant to fund most of this programming. The costs listed in the table above reflect the full cost of the program.

Program Energy and Capacity Savings

	2022-23 Actuals		2023-24 Actuals		2024-25 Actuals		2025-26 Forecast		2026-27 Forecast	
	GWh	MW	GWh	MW	GWh	MW	GWh	MW	GWh	MW
Online Energy Assessment for Homes										
Energy Assistance Program	0.9	0.1	2.2	0.4	2.2	0.4	2.8	0.5	TBD	TBD
Northern First Nations Home Retrofit Program	0.1	0.0	0.7	0.2	0.5	0.1	0.6	0.1	TBD	TBD
Northern Indigenous New Homes Program							-	-	TBD	TBD
Energy Efficiency Discounts Program			2.1	0.4	5.6	1.0	0.9	0.2	TBD	TBD
Home Efficiency Retrofit Rebate Program			0.0	-	0.3	0.1	0.2	0.0	TBD	TBD
Commercial Energy Optimization Program (CEOP)										
CEOP - Custom Incentive Services					0.3	0.1	1.6	0.2	TBD	TBD
Commercial Space and Water Heater Rebate Program					-	-	0.0	0.0	TBD	TBD
Residential Customer Engagement										
TOTAL	**1.0**	**0.1**	**5.0**	**1.0**	**8.9**	**1.7**	**6.1**	**1.0**	**TBD**	**TBD**

Note: 2026-27 energy and capacity savings are dependent on the amount and sources of funding, which will be finalized in Q1 of 2026-27.

c) SaskPower has no other programs.

SRRP Q74 Reference: Capacity Reserve Programs

a) Please comment on any changes that have occurred to the Spinning Capacity Reserve and Planned Operating Capacity Reserve programs since the last rate application.

b) Please provide a summary of subscriptions to the capacity reserve programs, including the total number of customers and the total amount of capacity subscribed to each rate option for each of the last three years.

Response:

a. There have been no changes that have occurred to the Spinning Capacity Reserve and Planned Operating Capacity Reserve programs since the last rate application.

b. Spinning Capacity Reserve

Year	Providers	Capacity (MW)
2023	3	73
2024	3	73
2025	3	73

Planned Operating Capacity Reserve

Year	Providers	Capacity (MW)
2023	1	50
2024	1	50
2025	1	50

SRRP Q75 Reference: Net Metering Program

a) Please discuss if SaskPower has made any changes to the Net Metering program, including terms and conditions and pricing, since the time of the last rate application. If so, please provide a summary of such changes.

b) Please provide a summary of subscriptions to the net metering program including the total number of customers subscribed, the total installed capacity, and the total generation delivered from customers to SaskPower under the program for each of the last three years.

c) Has SaskPower undertaken any engagement with net metering customers since the time of the last rate application? If so, please provide the results of that engagement.

Response:

a) No, SaskPower has not made any changes to the Net Metering Program's terms and conditions or pricing since the 2022 and 2023 Rate Application. The existing excess generation credit rate of 7.5¢ per kilowatt-hour remains in effect.

b) There are approximately 4,210 customers currently participating in the Net Metering Program.

	Total Participants	Total Installed Capacity (AC)	Total Generation Delivered
2023-24	3,160	44 MW	29 GWh
2024-25	3,600	49 MW	32 GWh
2025-26*	4,210	54 MW	36 GWh

*As of Jan 31, 2026

c) Yes, SaskPower conducts annual participant surveys with Net Metering Program customers to obtain insights into their experiences with the program. Surveys completed since the time of the last rate application include December 8-17, 2023, December 2, 2024 – January 5, 2025, and January 15 – February 8, 2026. Feedback is consistent year-over-year, in that respondents report that bill savings is the key motivator for program participation. Participants also express an interest in receiving a higher credit rate for excess power generation.

SRRP Q76 Reference: Cost of Service Study

a) Please provide a copy or weblink to the most recent external review of SaskPower's cost of service study methods.

b) Please provide a table showing:

   i. The recommended changes from the consultant
   ii. Whether SaskPower adopted the recommended changes and if not an explanation for why not.

c) Please discuss if there have been any other changes made to the cost of service study methodology since the last external review and if so, please itemize them and provide a discussion of the rationale for the change.

d) Please discuss when SaskPower anticipates its next external review of its cost of service methodology will take place.

Response:

a) Please see attached copy of the 2023 "Review of SaskPower Cost Allocation and Rate Design Methodologies" by Elenchus Research Associates.

b) Please see the table below. For more information, please refer to the 2026 or 2027 "Fiscal Test Embedded Cost of Service Study" report (pages 3 – 5, Section D).

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	Observations & Recommendations	Action	Comments
1	Recommend the continued removal of the Bary Correction from existing rates.	Accepted	Elenchus supports this change to SaskPower's rate design methodology.
2	If circumstances change in Saskatchewan and the marginal cost differentials increase, consideration should be given to implementing time-of-use rates as one possible demand management tool available to the utility, instead of building new capacity to meet increased demand for electricity.	Accepted	SaskPower continues to monitor changes to SaskPower's marginal cost of energy and will give consideration to implementing time of use rates if circumstances change.
3	Recommend SaskPower maintain its current rate design approach for customer classes without demand charges.	Accepted	SasPower agrees with maintaining the current rate designs until more AMI information is available.
4	SaskPower should begin the process of determining its rate structure it will implement for these customers once enhanced AMI billing data is available.	Accepted	SaskPower will examine potential options to recover more fixed costs as AMI data become more available.
5	Recommend SaskPower implement a plan for modest but frequent rate adjustments toward its target rates rather than relying on the infrequent larger adjustments	Deferred	Rate applications are a collective process, involving SaskPower, CIC, the SRRP and the Shareholder. Final decisions regarding frequency and the amount of the increases extend beyond SaskPower's authority.
6	Recommend SaskPower consider breaking out its Load function into separate functions in the future.	Declined	Breaking out the Generation load sub-function by different types of generation will not provide a material benefit or impact the classification or allocation of generation assets and expenses.
7	Continued support for the Average & Excess Method to classify Generation rate base and expenses	Accepted	The Average and Excess method reflects the use of the system by SaskPower's customers and apportions assets and costs based on how customers use the system.
8	Agree with SaskPower classifying transmission assets and expenses as 100% demand related.	Accepted	Elenchus supports SaskPower classification of transmission assets and expenses.
9	Implement the results of the Minimum System Method into the COS model.	Accepted	Results will be implemented in 2025 Cost of Service study.
10	Agrees with SaskPower's treatment of the carbon tax and use of rate riders to recover expense.	Accepted	Given the equivalency of the results and additional transparency, the methodology used by SaskPower is appropriate

c) Since the previous external review, there have been no additional modifications to the cost-of-service study methodology. However, minor financial reporting updates impacting 2026/27 are outlined below:

1) The Streetlight class is reported financially within the Commercial class and the Power – Contract class is being reported financially within the Power class. These amendments align to SaskPower's current financial reporting structure.

2) As of April 1, 2025, the provincial government directed SaskPower to stop collecting the Federal Carbon Tax from its customers.

   - Previously, as of April 1, 2019, the federal government implemented a Carbon Tax on fossil fuel emissions based on their carbon pollution pricing system, retroactive to January 1, 2019. The Federal Carbon Tax is based on predetermined emission thresholds set by the federal government on an annual calendar basis.

   - Until April 1, 2025, SaskPower elected to recover the Federal Carbon Tax through separate rate riders based on customers' energy consumption (kWh), rather than incorporating it into its published rates. As a result of this approach, expenses and revenue related to the carbon tax have never been included in the Cost-of-Service Study. Consequently, the suspension of carbon tax collection does not affect the results of the Cost-of-Service Study.

3) All Purchased Power Agreement (PPA's) assets are reported as a separate line item within the Cost-of-Service report, functionalized within Generation.

4) Organizational realignment of various Business units occurred throughout 2024 as follows:
   - SaskPower has consolidated NorthPoint, Generation, Transmission and Distribution into one business unit called Operations. Similarly, Asset Management, Technology & Security, and Finance have been consolidated under one business unit called Strategy, Technology & Finance. Procurement and Customer Experience (previously called Customer Services) have also been combined into a business unit called Customer Experience and Procurement. Although these units are now reporting from different areas, their rate base and expenses are still functionalized and classified in the same manner as they were previously.

d) SaskPower anticipates its next external review of its cost-of-service methodology will take place in 2028/29.

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Review of SaskPower Cost Allocation and Rate Design Methodologies

Final Report prepared by Elenchus Research Associates Inc.

30 June 2023

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1 OVERVIEW

SaskPower retained Elenchus Research Associates (Elenchus) to:

1. Review and assess SaskPower's existing cost of service methodology.
2. Review and assess common and accepted cost of service methodology in the electrical utility industry in Canada and the United States.
3. Survey the functionalization, classification, and allocation methodologies currently in use by Canadian electric utilities as well as the functionalization, classification, and allocation results in percentages.
4. Verify whether the current methodology is consistent with accepted electric power utility practices and is appropriate for SaskPower's system characteristics.
5. Propose, if required, the enhancement of SaskPower's cost of service methodology including the reasons for the changes.
6. Review SaskPower's rate design methodology.

This report consists of 5 additional sections.

Section 2 provides a very brief overview of the standard approach to cost allocation that is widely accepted by regulators across Canada and internationally.

Section 3 extends the discussion of the principles on which the Elenchus review is based by summarizing generally accepted rate making (Bonbright) principles, as the tailored version of those general principles that guide SaskPower approach to rate making.

Section 4 provides an overview of SaskPower's cost allocation methodology, recognizing that this methodology is fully documented in "2021 Fiscal Base Embedded Cost of Service Study", dated November 28, 2022, which has been prepared by SaskPower. Elenchus has reviewed this documentation to confirm that the SaskPower model is consistent with the documentation of the methodology.

Section 5 presents the results of Elenchus' review of the cost allocation methodologies currently used by selected (major) Canadian and U.S. electric utilities.

Section 6 contains Elenchus comments and recommendations based on our review of the SaskPower cost allocation model and its approach to rate design considering generally accepted regulatory principles, current standard practices across jurisdictions and the specific operational circumstances of SaskPower.

Section 7 describes the stakeholder process related to this review.

Appendix A includes the documentation of SaskPower's Cost Allocation Methodology.

Appendix B provides a list of the utilities surveyed and results of the jurisdiction review.

Appendix C includes the qualifications of the Elenchus' team that conducted the study and prepared this report.

Appendix D provides a response to the stakeholder question.

2 COST ALLOCATION

It is standard practice in Canada and in many jurisdictions internationally to rely on cost allocation studies to apportion a utility's assets and expenses to its customer classes using methods that are consistent with the NARUC Electric Utility Cost Allocation Manual.[1] Because most of the assets and expenses of an electrical power system are used jointly by multiple customer classes, cost allocation studies are used to apportion a utility's revenue requirement among customer classes on a fair and equitable basis as guided by the principle of cost causality.

Traditionally there are three steps that are followed in a cost allocation study: Functionalization, Classification (or Categorization), and Allocation.

Functionalization of assets and expenses is the process of grouping assets and expenses of a similar nature, for example, generation, transmission, distribution, customer service, etc. Hence, as a first step in a cost allocation study, each account in the utility's system of accounts is functionalized. That is, the function(s) served by the assets or expenses contained in each account is identified so that the costs can be attributed appropriately to the identified functions.

Classification (or Categorization) is the process by which the functionalized assets and expenses are classified as demand, energy and/or customer related. Hence, the costs associated with each function are attributed to these categories based on the principle that the quantum of costs is reflective of the quantum of system demand, energy throughput or the number of customers.

Allocation, which is the final step, is the process of attributing the demand, energy and customer related assets and expenses to the customer classes being served by the utility. This allocation is accomplished by identifying allocators related to demand, energy, or customer counts that reflect the relationship between different measures of these cost drivers and the costs that are deemed to be caused by each customer class. For example, if the necessary investment in a particular class of asset (e.g., certain transmission lines) is caused strictly by the single peak in annual demand, then the relevant costs would be allocated using the 1-coincident peak (1-CP) method. The actual application of these broad principles in the context of SaskPower is explained in section 4.

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[1] A standard reference document for cost allocation methodologies continues to be the **"**Electric Utility Cost Allocation Manual" published by the National Association of Regulatory Utility Commissioners (NARUC) in 1992. A subsequent NARUC publication, "Cost Allocation for Electric Utility Conservation and Load Management Programs" (1993) extends the application of the basic principles to conservation and demand side management (DSM) programs.

In some instances, assets and/or costs can be related directly to a particular customer class and are then directly assigned to the customer class, for example streetlight assets and expenses can be directly allocated to the streetlight customer class, by-passing the categorization step.

Cost allocation studies can be done using historical actual data or using future test year forecast data. The information needed is the utilities' financial data related to assets and expenses as well as sales data. The financial data are usually based on the accounting system used by the utility. The sales data used is required by customer class and includes, for example, number of customers, energy (kWh) consumption, and demand (kW or kVA) for customer classes that are metered and billed by demand.

Cost allocation studies are conducted periodically by utilities to compare the costs attributable to the various customer classes with the revenues being collected from the customer classes.

The ratio of revenue to cost (or revenue to revenue requirement) illustrates the extent to which the class is paying for their share of the costs borne by the utility. While recognizing that the allocation of costs cannot be done with precision, a revenue to cost ratio of 1.00 or above 1.00 indicates that the class is paying their fair share of costs or even more than their fair share. A revenue to cost ratio below 1.00 indicates that the class is not paying for their fair share of costs.

The analytic results are viewed as indicators since the allocation of shared costs amongst various customer classes cannot be done in a precisely accurate way. As a result, in many jurisdictions a range of revenue to cost ratio is accepted as reflecting the fair allocation of costs to customer classes instead of striving to achieve a revenue to cost ratio of exactly 1.00 for all customer classes. Many jurisdictions use a range of 0.95 to 1.05, or 0.90 to 1.10, as acceptable revenue to cost ratios when establishing revenue responsibilities by customer class.

3 GENERALLY ACCEPTED RATE MAKING PRINCIPLES

It is generally accepted by utility regulators that any utility's cost allocation methodology and approach to rate design should be based on a set of clearly enunciated principles. These principles then guide the work that is undertaken to allocate assets and expenses to customer groups appropriately and establish rates that recover those costs from customers in a manner that is consistent with the principles.

The most common reference for defining these ratemaking principles is the seminal work of James Bonbright.[2] Chapter 16 (pages 383-384) of the Second Edition sets out ten "attributes of a sound rate structure":

Revenue-related Attributes:

1. *Effectiveness in yielding total revenue requirements under the fair-return standard without any socially undesirable expansion of the rate base or socially undesirable level of product quality or safety.*
2. *Revenue stability and predictability, with a minimum of unexpected changes seriously adverse to utility companies.*
3. *Stability and predictability of the rates themselves, with a minimum of unexpected changes seriously adverse to ratepayers, and with a sense of historical continuity.*

Cost-related Attributes:

4. *Static efficiency of the rate classes and rate blocks in discouraging wasteful use of the service, while promoting all justified types and amounts of use:*
   (a) in the control of the total amounts of service supplied by the company;
   (b) in the control of the relative uses of alternative types of service by ratepayers (on-peak versus off-peak service or higher quality versus lower quality service).
5. *Reflections of all of the present and future private and social costs and benefits occasioned by the service's provision (i.e., all internalities and externalities).*
6. *Fairness of the specific rates in the apportionment of total cost of service among the different ratepayers, so as to avoid arbitrariness and capriciousness, and to attain equity in three dimensions: (1) horizontal (i.e., equals treated equally); (2) vertical (i.e., unequals treated unequally); and (3)*

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[2] *The Principles of Public Utility Rates*, James C. Bonbright, Albert L. Danielsen, David R. Kamerschen (Second Edition, 1988) Public Utilities Reports, pages 383-4.

anonymous (i.e., no ratepayer's demands can be diverted away uneconomically from an incumbent by a potential entrant).

7. *Avoidance of undue discrimination in rate relationships so as to be, if possible, compensatory (i.e., subsidy free with no intercustomer burdens).*
8. *Dynamic efficiency in promoting innovation and responding economically to changing demand and supply patterns.*

Practical-related Attributes

9. *The related, practical attributes of simplicity, certainty, convenience of payment, economy in collection, understandability, public acceptability, and feasibility of application.*
10. *Freedom from controversies as to proper interpretation.*

It is inevitable that in applying these principles, conflicts arise in trying to apply all the principles simultaneously. For example, an allocation that is more equitable may compromise economic efficiency or simplicity. Determining the optimal trade-offs between the principles in developing rates therefore requires judgment. For this reason, cost allocation and rate design are often referred to as being as much art as science.

SaskPower's six stated key objectives[3] for its cost of service study and resulting rate design are consistent with the Bonbright principles and appear to encompass all ten of the principles set out by Bonbright in 1988. The SaskPower objectives are:

1. Meeting revenue requirement
2. Fairness and equity
3. Economic efficiency
4. Conservation of resources
5. Simplicity and administrative ease
6. Stability and gradualism

The flowing sub-sections set out our interpretation of SaskPower's objectives.

[3] 2021 Fiscal Base Embedded Cost of Service Study, November 28, 2022

3.1 MEETING REVENUE REQUIREMENT

Meeting SaskPower's revenue requirement implies that customer rates should be set to yield sufficient revenues for the utility to recover its approved costs. The recoverable costs that make up the company's revenue requirement include all operating, maintenance and administration expenses, including amortization, as well as the cost of capital. The cost of capital includes both the interest on outstanding debt and a return on equity (or interest coverage) that enables the utility to be financially sound.

3.2 FAIRNESS AND EQUITY

Fairness and equity are understood to mean that the utility's assets and expenses have been apportioned to the customer classes in a manner that has cost causality as the main criterion. The methodologies used to apportion costs follow criteria that can be measured in a fair way and can be understood and accepted by stakeholders. Most of a utility's assets and expenses are shared by all or most of the utility's customers and cost causality parameters are developed to assign the assets and expenses to customer groups.

3.3 ECONOMIC EFFICIENCY

Economic efficiency means that the utility's assets and expenses are being utilized effectively (operational efficiency) and, to the extent practical, the rates charged to customers provide reasonable price signals that allow the utility to develop the power system in a manner that is efficient through time (dynamic efficiency).

3.4 CONSERVATION OF RESOURCES

Conservation of resources is a further dimension of economic efficiency in that the design of rates should result in price signals that encourage consumers to use power in a manner that maintains a reasonable balance between the cost of supplying power to consumers and the value of that power to consumers.

3.5 SIMPLICITY AND ADMINISTRATIVE EASE

Simplicity and administrative ease are criteria that address the need to use cost allocation and rate design methods that are understandable by stakeholders and customers and are implementable by the utility given its available capabilities and resources.

3.6 Stability and Gradualism

Stability and gradualism are criteria that deal with the need to use cost allocation and rate design approaches that produce stable results over time and manageable/gradual changes as a result of changing circumstances. The purpose of these criteria is to avoid, to the extent practical, approaches that produce sudden and significant changes in cost allocation and rate design because of changing circumstances. This is not intended as an impediment to appropriate changes, but rather a recognition that significant changes in the level of charges can be difficult for consumers to absorb in their daily lives. Hence, when circumstances justify changes that may have a significant impact on customer bills, it is desirable to phase in the changes in a manner that mitigates bill impacts without unduly compromising the other objectives of SaskPower's cost allocation and rate design.

4 SaskPower Cost Allocation Methodology

SaskPower cost allocation methodology[4] follows the standard industry approach of Functionalization, Classification and Allocation of assets and costs to customer classes.

4.1 Functionalization

The asset and expense functions utilized by SaskPower to group assets and costs of a similar nature include the following:

1. Generation:
    - i. Load
    - ii. Losses
    - iii. Scheduling and Dispatch
    - iv. Regulation and Frequency Response
    - v. Spinning Reserve
    - vi. Supplementary Reserve
    - vii. Planning Reserve
    - viii. Reactive Supply
    - ix. Grants in Lieu of Taxes
2. Transmission
    - i. Main Grid
    - ii. 230 kV & 138 kV Lines Radials
    - iii. 138/72 kV Substations

4 Ibid

iv. 72 kV Lines Radials

3. Distribution

   i. Area Substations
   ii. Distribution Mains
   iii. Urban Laterals
   iv. Rural Laterals
   v. Transformers
   vi. Services
   vii. Instrument Transformers
   viii. Meters
   ix. Streetlights
   x. Customer Contributions

4. Customer Service

   i. Metering Services
   ii. Meter Reading
   iii. Billing and Customer Accounts
   iv. Customer Collecting
   v. Service & Support
   vi. Customer Strategy & Planning

The functions used by SaskPower provide enough differentiation of assets and costs by grouping assets and costs of a similar nature in the cost allocation methodology to enable the classification and allocation of assets and costs to customer classes using cost causality principles. The extent of the breakdown into functions is consistent with other Canadian power utilities.

Additional details on the functionalization step followed by SaskPower in its cost allocation methodology are provided in Appendix A, which excerpts the details of the methodology from SaskPower's "2021 Fiscal Base Embedded Cost of Service Study".

Elenchus notes that section 5 of this report demonstrates that SaskPower's approach to functionalization is consistent with the best practices that are widely used by integrated electric utilities in other jurisdictions.

4.2 CLASSIFICATION

SaskPower classifies assets and costs into demand related, energy related and customer related, consistent with the standard practice of other Canadian power utilities. Classifying assets and costs into these three categories allows for the subsequent proper allocation of these assets and costs to customer classes.

The methodology currently used by SaskPower to separate generation rate base and depreciation expenses into demand related and energy related costs is the Average & Excess Demand method. This method considers the average annual demand required to meet its energy requirements, and any demand in excess of the average is required to meet peaking requirements. This method is used to classify all generation rate base, including wind generation.

The assets and expenses associated with Purchased Power Agreements (PPAs) are classified to demand and energy using the contractual capacity and energy payments for each plant.

The fuel expense for SaskPower units is classified as 100% energy related as is common practice in the cost allocation studies of other Canadian power utilities with rate regulated generation functions.

Transmission facilities are classified as 100% demand related. This also is the usual approach for these types of assets and costs.

Distribution substations and three phase feeders are classified 100% demand related. Urban and rural single-phase primary lines are classified 30% demand-related and 70% customer-related. Line transformers are classified 65% demand-related and 35% to customer-related based on the Minimum System Method.

All secondary lines, services, and meters are classified 100% customer related.

Customer related assets and costs are classified 100% to customer.

More details on the classification of assets and costs in SaskPower's cost allocation methodology are provided in Appendix A, which excerpts the details of the methodology from SaskPower's "2021 Fiscal Base Embedded Cost of Service Study".

Elenchus notes that section 5 of this report demonstrates that SaskPower's approach to classification is consistent with the best practices that are widely used by integrated electric utilities in other jurisdictions.

4.3 ALLOCATION

The last step in SaskPower's cost allocation study allocates the demand, energy and customer related assets and costs to SaskPower's customer classes. Classifying assets and costs into demand, energy and customer related allows for the allocation of these assets and costs using the appropriate parameters (i.e., allocators) that reflect cost causality. For example, it allows for energy consumed by a customer class to be used to allocate energy related assets and costs, and for the number of customers to be used to allocate customer related assets and costs that are driven by the number of customers.

Demand related generation assets and costs and transmission assets and costs are allocated to customer classes using the two coincident peak (2-CP) method based on demand, adjusted for the estimated associated losses. Energy related generation assets and costs are allocated to customer classes based on the energy consumed by customer classes, adjusted to include estimated losses.

Distribution demand related assets and costs are allocated to customer classes based on a combination of the two-coincident peak method for most functions and the Maximum Diversified Class Demands (MDD) method for the transformers function.

Customer related assets and costs are allocated to customer classes based on a combination of methods based on the number of customers by customer class for some assets and costs and the weighted number of customers by customer class for other assets or costs (e.g., where average per customer costs differ across classes, such as meter costs).

Elenchus notes that section 5 of this report demonstrates that SaskPower's approach to allocation is consistent with the best practices that are widely used by integrated electric utilities in other jurisdictions.

4.4 CUSTOMER CLASSES

The following is a list of the customer classes currently served by SaskPower, to which the functionally classified rate base and expenses are allocated. Each rate class may have multiple rate codes.

- Residential
- Farms
- Commercial
- Power - Published Rates
- Power - Contract Rates
- Oilfields
- Streetlights
- Reseller

More details on the allocation of assets and costs in SaskPower's cost allocation methodology are provided in Appendix A, which excerpts the details of the methodology from SaskPower's "2021 Fiscal Base Embedded Cost of Service Study".

SaskPower conducted studies to develop appropriate customer class load profiles based on valid sampling of customers. SaskPower also utilizes a study of losses to determine the losses incurred in providing electricity to its various customer groups.

More details on the customer load profiles and loss study conducted by SaskPower are provided in Appendix A, which excerpts the details of the methodology from SaskPower's "2021 Fiscal Base Embedded Cost of Service Study".

5 SURVEY OF FUNCTIONALIZATION, CLASSIFICATION, AND ALLOCATION METHODOLOGIES

Elenchus conducted a jurisdiction review of ten Canadian and US utilities with respect to the cost allocation methodologies currently being used in the industry. Special emphasis was placed on obtaining information from Canadian utilities.

Functionalization of assets and expenses, classification of functionalized assets, and allocation methodologies were surveyed, and the results of the survey are included in this section. More details of the jurisdiction review are provided in Appendix B.

As a result of deregulation in the electricity sector, some generators no longer use a cost allocation model to allocate their assets and costs to customer classes and to develop rates based on fully allocated costs. Instead, generators bid their supply to electricity system market operators or have bi-lateral agreements that have contracted prices. Hence revenues are based on market prices for electricity, rather than regulated rates.

The tables in this section reflect the results of the jurisdictional review and SaskPower's placement within each table. SaskPower's placement is denoted with an asterisk (*). For clarity, SaskPower is not included in the utility counts.

5.1 FUNCTIONALIZATION

5.1.1 GENERATION FUNCTIONALIZATION

The methodologies used to functionalize generation assets vary based on the generation assets owned and operated by each utility.

Functions are not always well-defined and are often broken out into subfunctions. The number of functions used by each utility does not necessarily reflect the degree of detail used in its cost allocation model since most generation functions are classified in the same way. A utility may have a single generation function for all its generation station assets, or it may list each generation station separately.

The number of generation asset and expense functions is summarized in Table 1.

Table 1: Functionalization methodology used for generation assets and expenses		
Number of Functions	Number of Utilities	Percent of Utilities
8-10	1*	10
6-7	1	10
4-5	1	10
2-3	5	50
NA	2	20
Totals	**10**	

5.1.2 Transmission Functionalization

The number of transmission asset and expense functions is summarized in Table 2.

Table 2: Functionalization methodology used for transmission assets and expenses		
Number of Functions	Number of Utilities	Percent of Utilities
6-8	2	20
3-5	1*	10
2	2	20
1	4	40
NA	1	10
Totals	**10**	

5.1.3 Distribution Functionalization

The number of distribution asset and expense functions is summarized in Table 3.

Table 3: Functionalization methodology used for distribution assets and expenses		
Methodology	Number of Utilities	Percent of Utilities
10-11	2*	20
8-9	2	20
6-7	2	20
4-5	4	40
Totals	**10**	

5.1.4 Customer Care Functionalization

The customer care category of functions includes assets and expenses associated with providing service to individual customers from the overall utility operations. Customer care functions typically include assets and expenses related to the service line, meter and meter reading, billing and collecting, and customer services.

Unlike the standardized labeling of generation, transmission, and distribution, this category of functions has different names across utilities. Alternate names include the “customer service and facilities function” or “retail services” function.

Some utilities include this function within the distribution function. The demarcation between the distribution function and customer care function can vary as well. In practice, the customer care functions are classified and allocated by similar methodologies regardless of the overall function in which they are assigned. For example, meter reading costs are classified as customer-related and allocated by a weighted customer count regardless of the function in which it belongs.

The number of customer care asset and expense functions is summarized in Table 4.

Table 4: Functionalization methodology used for customer care assets and expenses		
Methodology	Number of Utilities	Percent of Utilities
6	0*	0
5	1	10
4	4	40
3	3	30
2	2	20
Totals	**10**	

5.2 CLASSIFICATION

5.2.1 GENERATION CLASSIFICATION

There are a variety of methodologies used in the utility industry to classify generation between demand and energy related. The methodologies range from classifying all generation as energy related to classifying all generation as demand related; however, most classify a portion of the costs as demand and the balance as energy related reflecting that a utility's fleet must accommodate both the peak demand and the annual energy requirement of its customers. The choice of specific methodology should reflect the utility's circumstances.

One common approach is the *Average and Excess* method which classifies generation assets and costs using factors that combine each class's average demands over the test period with its non-coincident peak demands. The average demand 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.

In the *Equivalent Peaker* method, generation assets and costs are notionally separated into those deemed to serve peak demands and those that are deemed to be incurred to provide energy. The peaker assets and costs are allocated on a demand basis and the remaining assets and costs, deemed to be energy related, are allocated on an energy basis. The peaker assets and costs are the generation assets and costs of the units used to satisfy system peak demand.

In the *Peak and Average* method, a combination of the class contribution to 12 CP and class contribution to average energy usage is used to allocate generation.

The *Base and Peak* method is based on the concept that a peak kilowatt hour costs more than an off-peak kilowatt hour and that the extra costs should be borne by customers that impose the additional costs due to high demand in the peak period. Demand related generation costs are allocated the same as in the Equivalent Peaker method. The difference is in the allocation of energy related generation costs that are allocated to customer classes in proportion to peak energy use instead of total energy use.

The Judgmental Energy Weighting method recognizes that energy is an important factor in generation costs and judgment is used in determining the energy weighting. The NARUC manual uses as an example of judgment the peak and average allocator that adds together each class's contribution to system peak demand and its average demand.

SaskPower adopted the Average and Excess method following Elenchus recommendations in its 2017 Review of Cost Allocation and Rate Design Methodologies report. SaskPower has a high system load factor relative to other Canadian utilities, reflecting a flatter more consistent load shape. This system load characteristic results in a higher classification of generation costs to energy related and a lower classification to demand related.

The methodology used to classify generation assets and expenses are summarized in Table 5.

Table 5: Classification methodology used for generation assets and expenses		
Methodology	Number of Utilities	Percent of Utilities
Set by regulation	1	10
System Load Factor	4*	40
100% demand	1	10
3 CP Peak and Average	1	10
Fixed and Variable	1	10
NA	2	20
Totals	**10**	

Two surveyed utilities are in deregulated provinces (Alberta and Ontario) in which energy rates are based on market prices, so generation is not included in class cost allocation.

5.2.1.1 HYDROELECTRIC

Utilities appear to favour the load factor approach to classify hydroelectric generation. Four Canadian utilities surveyed used this method. Other methodologies for classifying some hydroelectric generation assets and expenses to energy are based on:

- the purpose of hydroelectric generation, base or peaking;
- the ratio of energy produced in an average year compared to extreme year; and/or
- the ratio between hydroelectric capacity factor and total system capacity factor.

Based on the review, the percentages of demand related classification of hydroelectric generation costs are summarized in Table 6.

Table 6: Classification of Hydroelectric generation costs to demand		
Percent Classified as demand	Number of Utilities	Percent of Utilities
90 - 100	2	20
70 - 90	0	0
50 - 70	1	10
35 - 50	3	30
Below 35	1*	10
NA	3	30
Totals	**10**	

5.2.1.2 BASE LOAD STEAM

The percentages of demand related classification of base load steam generation (coal, oil, or gas) costs are summarized in Table 7.

Table 7: Classification of Base Load Steam generation costs to demand		
Percent Classified as demand	Number of Utilities	Percent of Utilities
90 - 100	3	30
70 - 90	0	0
50 - 70	0	0
35 - 50	3	30
Below 35	0*	0
NA	4	40
Totals	**10**	

5.2.1.3 COMBUSTION TURBINE

The percentages of demand related classification of combustion turbine generation costs are summarized in Table 8.

Table 8: Classification of combustion turbine generation costs to demand		
Percent Classified as demand	Number of Utilities	Percent of Utilities
90 - 100	3	30
70 - 90	0	0
50 - 70	0	0
35 - 50	2	20
Below 35	0*	0
NA	5	50
Totals	**10**	

5.2.2 Transmission Classification

The percentages of demand related transmission costs are summarized in Table 9.

Table 9: Classification of transmission costs to demand		
Percent Classified as demand	Number of Utilities	Percent of Utilities
90 - 100	6*	60
70 - 90	0	0
50 - 70	0	0
35 - 50	2	20
Below 35	0	0
NA	2	20
Totals	**10**	

Transmission costs are usually classified as 100% demand related since transmission capacity is planned to accommodate the maximum system demand. Transmission includes the operation of the grid at different voltages as a single function that transports power from generating stations to the distribution system. Transmission also provides reliability to the electricity system by connecting multiple generation sources.

Transmission may be considered an extension of generation when it is connecting remote generators to the main grid. In this case, it may be classified into demand and energy in the same proportion as the generation it is connecting.

5.2.3 Sub-Transmission Classification

Some utilities may have an additional asset and expense function, sub-transmission system, which connects the transmission system to the distribution system. The definition of sub-transmission depends on the definition of Transmission. If Transmission assets are defined as 115kV and above, then 69 kV assets would be defined as Sub-transmission. In Ontario where Transmission is defined as assets above 50 kV, Sub-transmission is usually defined as 27.6 kV and 44 kV.

Sub-transmission assets and expenses are usually classified in the same proportion as the transmission system. The percentage of demand related costs for sub-transmission costs are summarized in Table 10.

Table 10: Classification of Sub-transmission costs to demand		
Percent Classified as demand	Number of Utilities	Percent of Utilities
90 - 100	7*	70
70 - 90	0	0
50 - 70	0	0
35 - 50	2	20
Below 35	0	0
NA	1	10
Totals	**10**	

5.2.4 Distribution Classification

Distribution assets connect the transmission assets to customers. Assets that are close to the transmission system tend to be classified as demand related in a manner similar to the transmission assets. 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.

Distribution costs are incurred for the overall system to reach each customer, to meet the peak demands of customers, and to provide the necessary connection and metering equipment of each customer. To determine what proportion of distribution costs are customer related and what proportion are demand related, there are two generally accepted methodologies being used by utilities: Minimum System method and Zero Intercept method.

The Minimum System method 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 can carry some electricity, therefore, some demand related costs would be included in the customer component.

The Zero Intercept method calculates the customer-related component of a distribution asset type by plotting a graph of the unit costs of different sized similar assets and using the value at the zero intercept in the graph to represent to customer component of the asset costs. Some utilities cannot use this method because they do not have sufficient data to undertake this regression analysis, Also, in some instances the regression results in a negative value at zero intercept, a result that is not credible. The classification methods used for line and transformers are shown in Table 11.

Table 11: Classification Method for Distribution Lines and Transformers		
Method	Number of Utilities	Percent of Utilities
Minimum System	3*	30
Zero Intercept	0	0
Both Minimum and Zero Intercept	3	30
Other	3	30
Judgment 50/50	1	10
Totals	**10**	

The proportion of distribution stations costs classified as demand related is shown in Table 12.

Table 12: Classification of Distribution Substation costs to demand		
Percent Classified as demand	Number of Utilities	Percent of Utilities
90 - 100	9*	90
NA	1	10
Totals	**10**	

The proportion of Primary Lines costs classified as demand related is shown in Table 13.

Table 13: Classification of Primary Lines costs to demand		
Percent Classified as demand	Number of Utilities	Percent of Utilities
90 - 100	4*	40
70 - 90	2	20
50 - 70	3	30
35 - 50	0	0
NA	1	10
Totals	**10**	

The proportion of Distribution Transformer costs classified as demand related is shown in Table 14.

Table 14: Classification of Distribution Transformers costs to demand		
Percent Classified as demand	Number of Utilities	Percent of Utilities
90 - 100	4	40
70 - 90	2	20
50 - 70	2*	20
35 - 50	1	10
NA	1	10
Totals	**10**	

The proportion of Line Transformer costs classified as demand related is shown in Table 15.

Table 15: Classification of Line Transformers costs to demand		
Percent Classified as demand	Number of Utilities	Percent of Utilities
90 - 100	3	30
70 - 90	3	30
50 - 70	2*	20
35 - 50	1	10
NA	1	10
Totals	**10**	

The proportion of Secondary Line costs classified as demand related is shown in Table 16.

Table 16: Classification of Secondary Line costs to demand		
Percent Classified as demand	Number of Utilities	Percent of Utilities
90 - 100	3	30
70 - 90	2	20
50 - 70	4	40
35 - 50	0	0
Below 35	1*	10
Totals	**10**	

The proportion of Services costs classified as customer related is shown in Table 17.

Table 17: Classification of Services costs to customer		
Percent Classified as customer	Number of Utilities	Percent of Utilities
100	10*	100
Totals	**10**	

The proportion of Meter costs classified as customer related is shown in Table 18.

Table 18: Classification of Meter costs to customer		
Percent Classified as customer	Number of Utilities	Percent of Utilities
100	10*	100
Totals	**10**	

5.3 ALLOCATION

5.3.1 GENERATION AND TRANSMISSION ALLOCATORS

1 COINCIDENT PEAK METHOD

The 1 CP allocation method allocates demand related costs to each customer class in proportion to the contribution of that customer class to the utility's maximum system peak. This method assumes that system capacity requirements are determined by the maximum demand imposed by customers on the system.

The advantage of this method is that it reflects cost causality assuming peak demand is in fact the sole driver of the costs allocated in this manner. Customers that impose peak costs on the system are responsible for those costs.

The disadvantage of this method is that customers that do not use the system at the time of the system peak or can reduce their consumption during the peak could end up using the system for free, or not paying their fair share of costs. For example, Streetlighting may not be allocated any costs if the peak occurs in the daytime. Another disadvantage is that if there are major system changes and the peak shifts to a different time, it could result in significant changes to class allocation factors over time, possibly causing rate instability.

12 COINCIDENT PEAK METHOD

The 12 CP method is like the 1 CP method but instead of using only one value for the year, it is based on each month's maximum peak. This method assumes that each monthly peak is important and not just the single annual peak.

The advantage of this method is that it addresses the disadvantage of the 1 CP method by reducing or eliminating entirely the possibility of using the system for free. The disadvantage of this method is that if the system had seasonal characteristics, using only one value for each month may not track costs properly.

VARIOUS COINCIDENT PEAK VARIATIONS

Variations to the 1 CP and 12 CP methods are methods that use a subset of highest demand months. Common variations are the 2 CP, 3 CP or 4 CP. The subset of months could be predefined as the months that typically have the highest demands or could use actual highest demands. This method is more stable than the 1 CP method but there could still be instability if the peak demand months fluctuate, particularly between winter and summer months. The methodology used by SaskPower is labeled the 2 CP method, which in fact includes 8 CP months. This measure accounts for demands in the two CP periods, summer and winter.

Another variation is that the coincident peak value may not necessarily be one per month, but could be for example, the highest 5 coincident peak values regardless of when they occur in the year.

1 NON-COINCIDENT PEAK METHOD

The 1 Class Non-Coincident peak method is based on the maximum demand by customer class, regardless of when they occur. Generally, the maximum demands by customer classes occur at different times and do not coincide with the system peak (maximum system demand). A ratio is developed by customer class based on the class maximum demand compared to the sum of all classes' maximum demands. This method is used to reflect cost causality for assets that are the closest to the customer or serve only similar type of customers.

12-NON-COINCIDENT PEAK

The 12 NCP allocation method is like the 1 NCP method, but instead of using just one maximum demand for the year, 12 monthly values are used. The ratios of class maximum demand to the sum of each class maximum demands are calculated for each month.

The allocation method for generation demand related costs is shown in Table 19.

Table 19: Allocation Method for Generation Demand Costs		
Method	Number of Utilities	Percent of Utilities
1 CP	2	20
2 CP	0*	0
3 CP	2	20
4 CP	2	20
12 CP	1	10
Highest 300 Hours	1	10
NA	2	20
Totals	**10**	

The allocation method for transmission demand related costs is shown in Table 20.

Table 20: Allocation Method for Transmission Demand Costs		
Method	Number of Utilities	Percent of Utilities
1 CP	4	40
2 CP	0*	0
3 CP	1	10
4 CP	1	10
12 CP	1	10
Other	1	10
NA	2	20
Totals	**10**	

The allocation method for sub-transmission demand related costs is shown in Table 21.

Table 21: Allocation Method for Sub-transmission Demand Costs		
Method	Number of Utilities	Percent of Utilities
1 CP	5	50
2 CP	0*	0
3 CP	1	10
4 CP	2	20
Other	1	10
NA	1	10
Totals	**10**	

5.3.2 Interruptible Load

Interruptible load reflects a type of service that is curtailed at the time of system maximum demand or other emergencies. Because of the possibility of curtailment, customers served under this condition pay less for electricity than customers supplied on a firm basis. Usually, the amount of the discount the customer receives is tied to the savings to the utility of not building peak capacity to serve the customer. Having this type of service allows for better utilization of the electricity system.

SaskPower has implemented a demand response program[5] that is based on the same principle as interruptible rates, better utilization of the electricity system in return for a discount. In the program, at times of capacity constraints, customers participating in the program that shift load receive financial compensation.

SaskPower accounts for the costs of the demand response program under Purchased Power. This treatment is acceptable since in the absence of the program, the utility would have to supply the shifted demand by purchasing the power from external sources.

5.3.3 Distribution Costs Allocators

Demand

The demand allocation methods for distribution costs are related to the proximity of the distribution asset to the end-use customer. Distribution assets that are further away from the customer and closer to the sub-transmission or transmission system are allocated to

5 https://www.saskpower.com/power-savings-and-programs/business/programs/demand-response-program

customer classes based on coincident demand allocators. The closer the distribution assets are to the customers, then the demand allocation method reflects the customer class's maximum demand, that is, non-coincident maximum demand.

CUSTOMER

Distribution costs that do not vary with customer consumption are classified as customer related and are allocated to customer classes based on number of customers by class or based on weighted number of customers. The weights are related to the type of assets or costs being considered and reflect cost causality. For example, meter reading assets and costs are weighted by the number of times the meter is read by customer class, e.g., monthly, by-monthly, and the relative cost of reading different types of meters.

The allocation method for distribution station demand related costs is shown in Table 22.

Table 22: Allocation Method for Distribution Station Demand Costs

Method	Number of Utilities	Percent of Utilities
1 NCP	7	70
12 NCP	1	10
Other	1	10
CP	1*	10
Totals	**10**	

The allocation method for distribution Primary Lines demand related costs is shown in Table 23.

Table 23: Allocation Method for Distribution Primary Lines Demand Costs

Method	**Number of Utilities**	**Percent of Utilities**
1 NCP	7	70
12 NCP	1	10
Other	1	10
CP	1*	10
Totals	**10**	

The allocation method for distribution transformers demand related costs is shown in Table 24.

Table 24: Allocation Method for Distribution Transformers Demand Costs		
Method	Number of Utilities	Percent of Utilities
1 NCP	8*	80
12 NCP	1	10
Other	1	10
Totals	**10**	

The allocation method for distribution secondary lines demand related costs is shown in Table 25.

Table 25: Allocation Method for Distribution Secondary Lines Demand Costs		
Method	Number of Utilities	Percent of Utilities
1 NCP	6	60
12 NCP	1	10
Other	3*	30
Totals	**10**	

The allocation method for distribution station customer costs is shown in Table 26.

Table 26: Allocation Method for Distribution Station Customer Costs		
Method	Number of Utilities	Percent of Utilities
# of Customers	2	20
NA (Stations 100% demand)	8*	80
Totals	**10**	

The allocation method for distribution primary lines customer costs is shown in Table 27.

Table 27: Allocation Method for Distribution Primary Lines Customer Costs		
Method	Number of Utilities	Percent of Utilities
# of customers	5*	50
Other	1	10
NA	4	40
Totals	**10**	

The allocation method for distribution transformer customer costs is shown in Table 28.

Table 28: Allocation Method for Distribution Transformers Customer Costs		
Method	Number of Utilities	Percent of Utilities
# of customers	5*	50
Other	1	10
NA	4	40
Totals	**10**	

The allocation method for distribution secondary line customer costs is shown in Table 29.

Table 29: Allocation Method for Distribution Secondary Lines Customer Costs		
Method	Number of Utilities	Percent of Utilities
# of customers	7*	70
Other	1	10
NA	2	20
Totals	**10**	

The allocation method for services customer costs is shown in Table 30.

Table 30: Allocation Method for Services Customer Costs		
Method	Number of Utilities	Percent of Utilities
# of customers	6	60
Weighted # of customers	4	40
Direct allocation	0*	0
Totals	**10**	

The allocation method for meter costs is shown the Table 31.

Table 31: Allocation Method for Meter Customer Costs		
Method	Number of Utilities	Percent of Utilities
# of customers	4	40
Weighted # of customers	6*	60
Totals	**10**	

5.4 Rate Design

There are various alternatives for rate design being used for different customer classes in the industry. They include:

- End use – Purpose of electricity use, for example residential, commercial, pumping load
- Energy or demand billed – How the customer is being billed: based on energy (kilowatt hours) or demand (kilowatts or kilovolt-amps)
- Density – Where the customer is located: in an urban (high density) area or a rural (low density) area
- Seasonal – When the customer consumes power: year-round or only during a specific season (e.g., summer cottages)
- Voltage of supply – Voltage that the customer is supplied electricity: transmission or high voltage, sub-transmission, primary, secondary, or low voltage

- Size – Amount of demand (kilowatts) or capacity that the customer consumes: e.g., above 50 kW, above 5 MW
- Load factor – Consumption pattern of electricity over time reflecting the costs that this pattern of consumption imposes on the utility, e.g., high load factor customers consume almost the same amount of electricity in all hours
- Quality of supply – Assurances of electricity supply, e.g., firm, interruptible
- Time-of-use – How electricity is charged to the customer, prices may vary by season, (e.g., winter summer), and by period (e.g., peak, off-peak)
- Unmetered – If electricity consumption is uniform then it does not need to be metered e.g., streetlight, cable TV

Traditional rate design aligns cost groupings with rate components. For each rate class a basic monthly charge is calculated to recover the costs allocated to the rate class that are classified as customer-related; a demand charge is calculated to recover the costs allocated to the class that are classified as demand-related; and an energy charge is calculated to recover the costs allocated to the class that are classified as energy-related.

In practice, utilities often deviate from designing rates that strictly reflect allocated costs. For example, utilities often implement “across-the-board” rate increases for all classes as long as the resulting revenue-to-cost ratios are reasonable. This approach maintains equity across classes in terms of the rate increases they receive. Rebalance of rates to align with the share of allocated costs is undertaken only when the revenue-to-cost ratio for one or more classes are deemed to be unreasonable. Utilities also often apply equal increases to all rate components within a class as long as the deviation between the revenue from each component and classified costs is reasonable.

Another reason rates may deviate from classified costs is the impracticality of utilizing a demand change when the customers’ demand is not measured. Demand meters are more expensive than energy meters so utilities have typically used energy meters for Residential and other low demand customers, and the rate design for those classes include only fixed monthly and energy charges. Utilities may also deviate from traditional rate design in response to technological changes, to better align variable rates with marginal costs, or to improve intra-class equity, rate stability, or revenue stability.

Different rate design is usually used by utilities for different customer classes to properly reflect the differences across customer classes and the individual utility’s operations.

6 ELENCHUS COMMENTS AND RECOMMENDATIONS

Based on our review of SaskPower's cost allocation methodology, our knowledge of standard practices in other jurisdictions across Canada and our review of the cost allocation practices of other electric utilities undertaken for this report, we are of the view that the methodology currently used by SaskPower is generally consistent with accepted rate making principles and practices as well as the methodologies commonly used by other electric utilities. Furthermore, SaskPower's cost allocation methodology is consistent with, and is reflective of, SaskPower's operational circumstances.

The following sub-sections outline observations on notable issues and recommended refinements that in our view merit consideration. As noted earlier, cost allocation is more of an art than a science; hence, adoption of any recommended changes to SaskPower's methodology should be dependent on the cost and/or availability of the required data, as well as the potential impact on the complexity of rates and the impact on customers. No changes should be implemented without due consideration and balancing of all the Bonbright principles of rate making as well as SaskPower's objectives and operational circumstances.

As stated in Page 67 of the NARUC manual:

> *Keep in mind that no method is prescribed by regulators to be followed exactly; and agreed upon method can be revised to reflect new technology, new rate design objectives, new information or a new analyst with new ideas. These methods are laid out here to reveal their flexibility; they can be seen as maps and the road you take is the one that best suits you.*

6.1 REVIEW OF EXISTING RATE DESIGN METHODOLOGY

Elenchus reviewed the current Rates Manual used by SaskPower.

SaskPower uses a basic monthly charge and energy charge (¢/kWh) for residential and energy billed small commercial customers. This is a common practice among utilities for these types of customer classes given the type of meters typically used for them.

Diesel supplied customers have a monthly charge and an inclining energy rate that reflects the significantly higher costs of diesel generation required to produce electricity for customers not connected to the electricity grid due to their remote location.

Farms and larger commercial customers with demand meters have a basic charge, a demand rate for consumption above 50 kVa/month and an energy rate that declines once the demand rates is applied.

Larger customers, (power standard, resellers), have a monthly charge, a demand charge, and an energy charge.

6.1.1 Coincident Peak Allocation Methodology

SaskPower previously applied an adjustment in its rate design to take into consideration the impact on intraclass equity due to variances in the load factors and coincidence factors of customers. This adjustment is known as the coincident peak allocation methodology, or the Bary correction. High load factor customers tend to have higher coincidence factors, that is, the higher the load factor for a customer the higher the chances that it will consume electricity at the time of the utility's maximum system demand which is the driver of capacity-related costs.

This adjustment shifted a portion of demand-related costs to instead be recovered through the energy charge. This deviated from standard ratemaking practice of aligning fixed charges with fixed costs, demand charges with demand-related costs, and energy charges with energy-related costs. At a class level the revenue collected from customers before and after the rate design adjustment remained unchanged so there were no inter-class equity issues. From a cost causality perspective, rates set with this adjustment were considered more equitable as it resulted in customers within a class being billed at levels that generally corresponded more closely to the costs they caused.

However, this adjustment distorted the price signal for energy and demand charges. The overstated energy prices created a false price signal for customers to self-generate. Customers that self-generated to avoid energy charges were avoiding not only energy-related costs but also the demand-related costs that were shifted to the energy charge. The demand-related costs caused by customers with self-generation were not recovered from those customers, shifting costs to customers that didn't cause those costs.

This price signal also encouraged grid defection. A significant portion of SaskPower's revenue requirement is associated with fixed or semi-fixed costs that are shared among customers. Defection from the grid will cause those costs to be recovered from a smaller number of customers and lower level of billing determinants (kWh or kVA) resulting in higher bills for the remaining customers. This is a growing concern as self-generating technologies and Distributed Energy Resources (DERs) become more cost effective.

Starting in 2022, this adjustment is gradually being phased out of SaskPower's rate design over time. Elenchus supports this change to SaskPower's rate design methodology.

6.1.2 Time-of-Use Rates

Time-of-use rates have been implemented by some utilities to send a more refined price signal to customers on the costs of consuming electricity at different times of the day, days of the week, and seasons through the year. Generation costs are normally the largest component of electricity supply costs and any reduction in total generation costs in response to this price signal could provide benefits to the utility and consumers in the form of lower utility costs and therefore lower customer bills. The intent of time-of-use rates is that if customers have the proper price signals with enough incentives to modify behaviour, they will change their consumption patterns and reduce their usage during high-cost periods, even if consumption is increased during low-cost periods. Reducing consumption in high-cost periods allows the utility to reduce its total costs by reducing the requirement for peak capacity or for purchasing expensive fuel or imported power at times of high demand.

Implementing time-of-use rates (TOU rates) requires that the proper infrastructure be in place in the form of “smart” meters that are capable of recording, for example, hourly consumption. Implementing TOU rates also requires meter reading and billing systems capabilities that enable the processing of the required data. The assets and software required to implement time-of-use rates are such that it may be justifiable in locations with high supply costs differentials between high demand and low demand periods.

However, TOU rates may not be economic for a utility or its customers in instances where the differential in marginal costs between high and low demand periods is small. For example, where the capacity and fuel cost savings are not large enough to offset the infrastructure costs required to implement time-of-use rates, introducing TOU rates may not be cost effective. As with any other investment, a decision on implementation should be based on a sound business case. The business case for TOU rates can be approached either by considering only the utility’s generation and network costs and savings, or by also building in external costs, such as environmental and health benefits. The goal of TOU rates should not be to benefit “free riders” who have low consumption in high-priced periods in any case, but to shift demand and reduce the average cost of power.

For time-of-use to achieve the goal of changing consumption patterns, the differential in prices between high and low-cost periods must provide sufficient incentive for customers to modify their behaviour without resulting in undue sacrifices. It also should reflect the utility’s characteristics that would result in savings because of lower consumption during high-cost periods. In particular, if the marginal cost of supply is essentially the same in all hours of the year shifting demand will not reduce the utility’s total costs or customer bills.

In SaskPower’s case, it is Elenchus’ understanding that a reduction in customers’ electricity consumption during high-cost periods would not result in significant fuel cost savings to SaskPower. Currently natural gas is the fuel used at the margin to supply capacity at times of high electricity demands and if consumption is shifted to periods of low electricity consumption, natural gas is still the fuel that is used at the margin to supply power during periods of low electricity consumption.

Time-of-use for transmission costs may make sense in instances when there is capacity constraint in the transmission system, but transmission costs are not a large component of customers’ total electricity bill. In the case of electric utilities that implement TOU rates based on generation cost differential, time differentiated transmission rates may be implemented to complement the time differentiated generation rates and thus provide a consistent total-system price signal to customers.

Distribution costs are for the most part fixed for a utility and are not dependent on the customer's electricity consumption, therefore time differentiated distribution rates may not be appropriate from a cost causality perspective in circumstances where electricity rates are bundled so that the distribution rate recovers all generation and transmission costs, as well as the utility's distribution costs.

It is Elenchus' understanding that SaskPower operates an electricity system that already has a high load factor of 75% and is projected to become even higher because of the addition of new load that is for the most part flat consumption load. Operating a system with high load factor limits the expected benefits of implementing time differentiated rates to encourage load shifting. The levels of time differentiate rates are generally based on the marginal cost in the different defined time-of-use periods. If circumstances change in Saskatchewan and the marginal cost differentials increase, consideration should be given to implementing time-of-use rates as one possible demand management tool available to the utility, instead of building new capacity to meet increased demand for electricity.

6.1.3 Rate Alignment

SaskPower's rate design is generally consistent with the standard utility practice of adopting rates for all classes that align each rate component (fixed charge, demand charge and energy charge) with the corresponding classified costs (customer-related, demand-related, and energy-related) to the extent practical and reasonable. Where necessary or appropriate due to limitations on metering technology (e.g., customer demand is not measured) or to avoid violating rate design objectives such as avoiding rate shock for customers, strict alignment of cost and rate components may not be justified. Hence, judgment generally guides reliance on the results of a cost-of-service study in designing rates.

As noted above, SaskPower's rate design previously included a coincident peak allocation methodology (Bary Method) that shifted the recovery of a portion of demand related costs from the demand charge to the energy charge to improve intra-class equity. This novel approach improved the alignment of costs and revenues on an intra-class basis, but the misalignment of costs and rate components led to other issues as a result of uneconomic self-generation being made cost-effective for individual customers, even when the all-in cost of power for all customers increased. Uneconomic self-generation occurs when the incremental cost of self-generation exceeds the avoided costs resulting from the reduction of load supplied by the existing power system.

Although the Bary Method reduced intra-class inequities for customers with load and coincidence factors that differed significantly from the class averages, it required notable misalignment of rate components and classified costs. By adopting self-generation, some customers could reduce their bills by far more than the avoided system costs. As a result, the savings enjoyed by customers that adopted self-generation came primarily from shifting cost responsibility to other customers rather than from the reduction of the total cost of meeting the demand of Saskatchewan customers. Action that reduces bills for self-generating customers while increasing total costs for all Saskatchewan electricity consumers is uneconomic from the perspective of Saskatchewan's overall electricity system.

Put differently, the misalignment of rate components with classified costs risks motivating self-generation that results in stranded costs. A utility's demand related costs are fixed and are incurred based on planned or anticipated demand. After the investment is made those costs continue to be incurred even if demand is reduced or anticipated incremental demand does not materialize. Using self-generation to avoid future system expansion investments can be economic in some circumstances, but self-generation is rarely economic when the primary impact is to strand embedded costs.

The theoretically ideal solution to this problem is to implement demand charges for all customer classes where the billing determinant is coincident peak demand. Unfortunately, while this approach is conceptually optimal it is not practical. Some rate classes do not have demand charges because installing higher-cost demand meters for relatively low-demand customers has not been cost effective. In the near future, implementing demand rates for all metered rate classes will be possible following the rollout of Advanced Metering Infrastructure (AMI). But even with AMI, billing on the basis of coincident peak demand is problematic for most customers since it provides a price signal that few customers can respond to. The timing of system peaks is not known in advance so customers cannot manage their demand to avoid system peaks.

Elenchus notes that SaskPower's current rate design methodology for rate classes without demand charges, principally the residential rate class, recovers all demand-related costs within the energy charge which is a standard practice across jurisdictions.[6] Energy and demand costs vary by a customer's use so recovering those costs through the variable energy charge will align intra-class costs with revenues provided that the coincidence and load factors of individual customer are fairly close to the class average. This method also maintains the alignment of a basic monthly charge with customer related costs.

6 By using the minimum system methodology to classify distribution costs between customer and demand, a nominal amount of demand is considered customer-related and recovered through the basic monthly charge.

An alternative approach would be to assign a portion of demand related costs to be recovered in the basic monthly charge. This approach would more closely align with recovering fixed costs through a fixed charge and recovering variable cost through a variable charge. This rate design approach would result in increased bill and revenue stability for both customers and SaskPower. Under the status quo rate design a reduction in Residential consumption would cause a corresponding reduction in energy related costs which vary with demand (especially fuel costs for generation), and demand related costs that are not reduced when demand is reduced.

The problem with this latter approach is that assigning demand related costs to the basic monthly charge may be considered inequitable in circumstances in which customers have little or no demand, such as seasonal customers, and customers with minimal electricity consumption. These customers will be paying for demand related costs they do not cause within basic monthly charges. The implicit demand component in the monthly charge will reflect the average per customer demand of customers in the class, rather than the individual customer's actual demand. A further potential concern is that, although unlikely in the near-term for Residential and other non-demand charge customers in Saskatchewan, higher basic monthly charges create an increased risk of grid defection in the future.

Elenchus also notes that a move away from the current approach would provide an inappropriate price signal for customers. Shifting cost recovery away from variable charges excessively may encourage uneconomic customer response in which the costs caused by consumption and demand are greater than the variable revenue recovered from customers. From a customer's perspective, shifting a portion of the bill from avoidable variable charges to fixed monthly charges could negatively impact low volume customers, particularly low-income residential customers. In Elenchus's view, maintaining the price signal and bill structure faced by SaskPower's customers with blended energy/demand charges outweighs the potential benefit of revenue stability that can be achieved by shifting demand cost-recovery to monthly charges.

Elenchus recommends that SaskPower maintains its current rate design approach for customer classes without demand charges. SaskPower should begin the process of determining its rate structure it will implement for these customers once enhanced AMI billing data is available.

It was noted in a public stakeholder meeting related to this review that changes to SaskPower's rate design can take many years to implement. When there is a compelling reason for SaskPower to modify its rate design it would be in the best interest of both SaskPower and its ratepayers to begin implementing those changes on a more timely basis. Delays in implementing new rate designs can cause larger bill impacts once implemented, can inappropriately encourage uneconomic customer behaviour, and exacerbate the issue the new rate design is intended to solve.

Elenchus recommends SaskPower implement a plan for modest but frequent rate adjustments toward its target rates rather than relying on the infrequent larger adjustments that would otherwise be needed to reach the target rate design by a similar target date. This approach to its rate design would be more consistent its stated guiding principle of Stability and Gradualism.

6.2 MAIN FUNCTIONALIZATION, CLASSIFICATION AND ALLOCATION METHODOLOGIES

6.2.1 FUNCTIONALIZATION OF GENERATION ASSETS AND EXPENSES

The appropriate functionalization method groups assets and expenses that are incurred for similar purposes. The selection of functions should strike a balance between providing a sufficient division of assets and expenses without adding unnecessary complexity by adding many functions that are classified in the same manner. The appropriate selection of functions should also consider the practicality of having functions that align with line items within financial statements.

Generation Plants

SaskPower has nine generation functions: Load, Losses, Scheduling & Dispatch, Regulation & Frequency Control, Spinning Reserve, Supplementary Reserve, Planning Reserve, Reactive Supply, and Grants in Lieu of Taxes. The Load function includes all sources of SaskPower’s generation.

Utilities typically functionalize generation into different types of generation. The same classification factors are often applied to each generation function; however, this could evolve over time with changes to load dispatch. The carbon charge provides an economic incentive to dispatch more lower-emitting generation sources, thereby shifting more costs to peak generation.

Elenchus recommends for SaskPower to consider breaking out its Load function into separate functions in the future. This will not impact the classification or allocation of generation assets or expenses in the short term but will provide SaskPower with the flexibility to change generation classification methodologies in the future.

System Operator Functions

Scheduling & Dispatch and Regulation & Frequency are typically considered system operator functions. In deregulated jurisdictions, such as Ontario and Alberta, the system operator is an entity separate from any regulated utility. In vertically integrated utilities like SaskPower, these functions are typically grouped with transmission functions. Elenchus recommends moving the Scheduling & Dispatch and Regulation & Frequency functions to transmission.

Other Generation Functions

Of SaskPower's nine generation functions, four functions serve similar purposes and are classified and allocated on the same basis. These four functions are Spinning Reserve, Supplementary Reserve, Planning Reserve, and Reactive Supply. Elenchus notes other utilities do not functionalize these functions as distinct functions in their class cost allocation methodologies. SaskPower advised that this breakout is used for its Open Access Transmission Tariff (OATT) cost allocation and rate design process.

These functions could be combined or absorbed into the load function for consistency with other utilities, however, there is no compelling reason to stray from current practice in its class cost allocation model other than simplification.

Losses

SaskPower has separate Load and Losses generation functions. No other utility reviewed by Elenchus has a separate Losses function. To functionalize losses, SaskPower attributes some total energy costs to losses in proportion to the share of losses within the generation requirement. Likewise, a share of total demand costs is attributed to demand losses in proportion to the share of demand losses within peak demands. This attribution of generation costs provides a rate base and expense associated with losses.

The Load function is allocated based on energy and demand without losses. The Losses function is allocated based on the losses of each class. These allocations differ because classes served at higher voltages have lower losses.

Other utilities do not implement the initial step of separating load-related rate base and expenses and losses-related rate base and expenses.

Other functions that are classified as energy and/or demand are allocated based on losses-adjusted energy and losses-adjusted demand, so Load is the only function allocated based on energy and demand without losses.

Though uncommon, Elenchus does not see a compelling reason for SaskPower to change its methodology. A change to the conventional methodology used by other utilities would not result in a change in the quantum of costs allocated to each rate class.

6.2.2 Classification of Generation Assets and Expenses

Different methodologies are generally used to classify generation costs from a utility's own generation system compared to the classification of purchased generation from external sources. This is the case for SaskPower.

SaskPower's Generation Fleet

SaskPower uses the Average and Excess method to classify generation expenses. This methodology, as described in the NARUC Manual, page 49, is a commonly used and accepted methodology to classify generation assets and expenses. The method uses factors that combine classes' average demand and non-coincident peak demands. SaskPower used rate codes information instead of customer class information to develop the necessary customer consumption data.

The Average and Excess method reflects the use of the system by SaskPower's customers and apportions assets and costs based on how customers use the system.

6.2.3 Classification of Transmission Assets and Expenses

SaskPower classifies transmission assets and expenses as 100% demand-related and this is an accepted approach in the industry. As seen in the survey results six out of eight utilities surveyed classify transmission assets and expenses as 100% demand related.

Elenchus supports SaskPower classification of transmission assets and expenses.

6.2.4 Classification of Distribution Assets and Expenses

Lines and transformers are the largest cost items in the distribution of electricity to customers. Six of the ten utilities surveyed use the minimum system to classify some component of the distribution system as customer related.

Currently, SaskPower uses in its cost allocation study survey results to classify distribution costs between demand and customer related for lines and transformers. SaskPower tried to use the Zero Intercept method but was unable to obtain the necessary supporting data. SaskPower collected the necessary data to calculate the results of classifying distribution assets and expenses based on the minimum system approach.

The Minimum System method is used to classify distribution lines and distribution transformer assets and expenses between demand and customer related. The data required for the Minimum System method reflects the current minimum size distribution transformers and distribution lines used by the utility in serving customers and uses replacement assets and expenses to estimate the value of the minimum system. The ratio of the cost of the minimum system to the cost of replacing all existing distribution transformers and distribution lines would represent the customer component percentage.

6.3 *Survey of Classification and Allocation Methodologies*

The results of the utility survey conducted by Elenchus has been discussed in section 5 above and more details are provided in Appendix B below.

6.3.1 Minimum System Method

Elenchus reviewed SaskPower application of the Minimum System method for its distribution lines and distribution transformers.

The customer related proportion of lines and transformers is usually higher than average for low density utilities. SaskPower has very low density, approximately 3 customers per kilometers and the lower the customer density the higher the customer related component for distribution lines and distribution transformers. This is an expected result as assets are being utilized by fewer customers and distribution assets are required regardless of how much electricity customers consume.

As an example, in Ontario, the Ontario Energy Board uses the following default values for the customer component of lines and transformers based on the electricity distributor density:

- If density is less than 30 customers per kM of lines, customer component is 60% for lines and transformers
- If density is between 30 and 60 customers per kM of lines, customer component is 40% for lines and transformers
- If density is higher than 60 customers per kM, customers component is 35% for lines and 30% for transformers

SaskPower's minimum system study produces the following results:

- Distribution lines - 68.5% customer related, 31.5% demand related
- Distribution transformers – 35.5% customer related, 64.5% demand related

These results are marginally different than the percentages currently used by SaskPower in its cost allocation study. Distribution lines are classified as 70% customer related and 30% demand related and distribution transformers are classified 35% customer related and 65% demand related. Some utilities surveyed by Elenchus use minimum system and similar studies as checks of the reasonableness for rounded classification splits, however, it is Elenchus' view that the precise figures should be used if they are available.

The results of the minimum system study should be implemented by SaskPower in its cost allocation study considering the impact of the change on customers' revenue requirement and related revenue to cost ratios. A multi-year implementation may be necessary to mitigate customers' bill impact, however, Elenchus anticipates this change will have a minimal impact on revenue to cost ratios.

To address the concern that the minimum system can carry some electricity and that some demand related costs would be included in the customer component 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 assets. The capacity of the smallest distribution assets 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.

SaskPower uses the PLCC adjustment to classify distribution lines and transformers to demand related and customer related. Elenchus supports this methodology as the PLCC adjustment attributes the costs of a minimum system as customer related and the costs incurred to meet capacity requirements as demand related more precisely than a methodology without this adjustment.

6.3.2 Winter/Summer Allocation (2 CP)

In jurisdictions where electricity markets have been opened to competition, such as Ontario and Alberta, generation costs are bid to the system market operator by generators and are not classified and allocated to customers using a traditional cost allocation methodology. Transmission companies in these competitive markets are also usually not allowed to own generation assets. This is the situation in which two of the utilities surveyed operate.

The survey results show that the method used to allocate demand-related generation assets and costs by five out of eight utilities involves using more than one coincident peak as the allocator: three, four and twelve coincident peak values are used.

For transmission demand-related assets and costs four out of eight utilities use the one coincident peak method as allocator and the other four utilities use more than one coincident peak as an allocator: three, four or twelve peaks are used.

SaskPower uses the 2 CP allocation method to allocate generation, transmission and primary distribution lines demand related assets and costs to customer classes to reflect cost causality. For secondary distribution lines demand related assets and costs SaskPower uses the one class non-coincident peak method.

Based on information from SaskPower staff the capacity of network equipment in the summer can be reduced by as much as between 20% to 30% of the winter capacity due to the effect of higher summer temperatures on the actual loads that the facilities can handle. As a result, for some facilities, even though SaskPower is a winter peaking utility, it is the summer capacity requirement that determines the necessary installed capacity of certain facilities. Additionally, SaskPower staff informed Elenchus that urban areas served by SaskPower tend to have maximum demands in the summer, while rural areas tend to have maximum demands in the winter. This fact further supports the concept of using 2-CP as the allocation method for demand related assets and expenses.

6.3.3 Coincident and Non-Coincident Peak Allocators

SaskPower currently uses 5 years of historical data to develop the demand and energy allocators. The number of years of historical data to be used varies significantly across jurisdictions. Based on the survey of utilities, the number of years of historical data used can be: 1, 3, 5, 8, 10, or 22 years.

Elenchus is of the view that as a minimum 3 years of data should be used to eliminate unusual events that may occur in one year and to provide more representative load profiles. Elenchus opinion is that SaskPower's use of 5 years of historical data is appropriate.

6.3.4 Functionalization of Overhead Costs

In general, utilities classify overhead assets and expenses in the same proportion as other assets and expenses. Some overhead assets or expenses are classified as all other assets or expenses, while some overhead assets or expenses that are more specific and dedicated to a specific function are classified following those specific functions. For example, head office expenses would be classified as all other expenses, vehicles used for building and maintaining lines would be classified between Transmission and Distribution functions based on Transmission and Distribution line assets. Using this approach ensures that the effect of the classification of overhead costs is neutral and it does not alter the overall classification of assets and costs. Similarly, the allocation of overhead assets and expenses is based on the allocation of other assets and expenses to customer classes. It is Elenchus' understanding that SaskPower's classification and allocation of overhead costs follows the same approach, it is classified and allocated in the same manner as other assets and expenses.

Elenchus endorses this approach. There is a very loose causal relationship to support the allocation of overhead costs to customer classes. There is significant merit in allocating these costs in direct proportion to all other costs, where there is a more directly discernible causal relationship.

Based on Elenchus experience, this approach is commonly applied by utilities in other jurisdictions.

6.3.5 Carbon Pricing

As of 2019 SaskPower is required to pay the Federal Carbon Tax on consumption of its carbon-emitting fuels.

SaskPower has included the Federal Carbon Charge as a separate line item on customer bills. The carbon charge is the same for all kWh consumed, aside from a class-specific adjustment for losses. This methodology treats the carbon charge as a pass-through item that is separate from SaskPower's revenue requirement and is not included within the cost allocation model. This methodology provides a transparent line item for the carbon charge to be included on customer bills.

Alternatively, the carbon charge expense could be included in the revenue requirement and flow through the cost allocation model in which case it would be functionalized either as its own generation function or included as part of the fuel function because the cost is caused by fuel consumption. The expense would be classified as energy-related in the same way fuel costs are classified and allocated by losses-adjusted energy consumption.

The cost allocation methodology described above produces the same result as the outside-the-model losses-adjusted calculation, aside from minor differences due to class deviations from 1.00 revenue to cost ratios. Given the equivalency of the results and additional transparency, the methodology used by SaskPower is appropriate.

7 Stakeholders Comments

The review of SaskPower's cost allocation and rate design methodology stakeholders included two opportunities for stakeholders to submit written questions and an opportunity to provide written submissions. One written question and no written submissions were received from stakeholders during this review process. The question concerned SaskPower's rate design objectives, so SaskPower provided the response. The question and response are provided as Appendix D. Elenchus agrees with SaskPower's response.

APPENDIX A: SASKPOWER COST ALLOCATION METHODOLOGY DOCUMENTATION

The information below was extracted from a document titled: “2021 Fiscal Base Embedded Cost of Service Study” prepared by SaskPower.

Functionalization

1. Rate Base Items

1.1 - Plant in Service & Accumulated Depreciation

SaskPower Generation, Transmission, and Distribution:
All of the rate base accounts are functionalized on the basis of the plant designation; generation plant is functionalized entirely to the generation function; transmission plant is functionalized to transmission and distribution plant is functionalized entirely to distribution. The plant in service and accumulated depreciation for Wind Projects are included within SaskPower generation. The sub-functionalization is relatively straightforward using SaskPower’s detailed accounting records. The sub-functionalization of generation assets to ancillary service which is required for SaskPower’s OATT tariffs is more complicated. It is important to note, however, that the generation load and losses sub-functions and all ancillary services sub-functions are allocated to all full-service customers.

Coal Reserves:
SaskPower coal reserves are functionalized to the load and losses sub-functions within the generation function.

Shand Greenhouse:
The Shand Greenhouse assets are functionalized to generation. The sub-functionalization is the same as the total for all SaskPower generation.

Purchased Power Agreements:
The assets associated with Purchased Power Agreements are functionalized to generation.

Meters and Instrument Transformers:
Meters and instrument transformers are included in the meters and instrument transformers sub-function within distribution.

General Plant - Unused Land:
The functionalization and sub-functionalization of unused land is done using Operations, Maintenance and Administration expense (OM&A).

General Plant - Right of Use Land:
The functionalization and sub-functionalization of right-of-use land is done using Operations, Maintenance and Administration expense (OM&A).

General Plant – Buildings:
The functionalization of the SaskPower head office building and other buildings is done using Operations, Maintenance and Administration (OM&A) expense.

General Plant – Right of Use Buildings:
The functionalization and sub-functionalization of right-of-use buildings is done using Operations, Maintenance and Administration (OM&A) expense derived from buildings, excluding Head Office, Research & Development, Storage and Residential Buildings.

General Plant - Office Furniture & Equipment:
The functionalization and sub-functionalization are the same as for buildings.

General Plant - Vehicles & Equipment:
The functionalization of the Vehicles and Equipment is based on the vehicles and equipment asset summary report by profit center. The asset values for vehicles and equipment are then prorated to sub-functions within each function using Operations, Maintenance and Administration (OM&A) expense.

General Plant - Computer Development & Equipment:
The functionalization of the computer development and equipment is done in two steps. In the first step the asset value for computer development and equipment is divided into mainframe systems and desktop. In the second step the main frame assets (software and hardware) is functionalized on an application-by-application basis and desktop assets (hardware and software) are functionalized using the number of employees. The asset values for computer development and equipment are then prorated to sub-functions within each function using Operations, Maintenance and Administration (OM&A) expense.

General Plant - Communication, Protection & Control Equipment:
Communication, Protection & Control Equipment is functionalized to generation, transmission, distribution, and customer services based on an evaluation of each type of asset and using advice from SaskPower's Transmission Services staff.

General Plant - Tools & Equipment:
The functionalization of the Tools and Equipment is based on the asset history by function report. The asset values for tools and equipment are then prorated to sub-functions within each function using Operations, Maintenance and Administration (OM&A) expense.

1.2 - Allowance for Working Capital

The allowance for working capital is consistent with Cost of Service methodology that a utility should sustain a suitable level of working capital to meet its current obligations such as payroll, taxes etc. The allowance for working is calculated as 12.5% of the sum of Operations, Maintenance and Administration (OM&A) expense, corporate capital tax, grants in lieu of taxes and miscellaneous tax expense and is prorated to functions and sub-functions using the sum of these expense items.

1.3 - Inventories

SaskPower accounting records summarizes inventory cost by Power Production and Transmission and Distribution. The inventories are then prorated to sub-functions within the generation, transmission and distribution functions using Operations, Maintenance and Administration expense (OM&A).

1.4 - Other Assets

Other assets (deferred assets and prepaid expenses) are grouped into 4 categories as follows:

- **Natural gas / coal related:**
  Functionalized to generation.

- **Employee related:**
  Functionalized using head count by Business Unit / Support Group.

- **Insurance expense related:**
  Functionalized using information provided from SaskPower's Risk management staff.

- **Miscellaneous:**
  Prorated to sub-functions within each function using Operations, Maintenance and Administration (OM&A) expense.

2. Revenue Requirement Items

A summary of the functionalization methodology for expense plus the return on rate base items is provided below:

2.1 - Fuel Expense SaskPower Units

The fuel expense for SaskPower units is functionalized 100% to generation.

2.2 - Purchased Power and Import

The purchased power expense is functionalized 100% to generation.

2.3 - Export & Net Electricity Trading Revenue

Export revenue is treated as an offset to fuel expense and as such is functionalized 100% to generation.

2.4 - Operating, Maintenance & Administration (OM&A) Expense

Power Production Business Unit:

The OM&A expenses for the Power Production Business Unit and Purchased Power Agreements (PPA's) are functionalized to generation.

Transmission & Distribution Business Unit:

A small amount of the Transmission and Distribution Business Unit's OM&A expense relating to the transmission planning, scheduling & dispatch and generation regulation and frequency response are functionalized to generation. The remainder of the OM&A expense for the Business Unit is split to transmission and distribution using cost centre reports.

- Transmission OM&A is sub-functionalized by separating transmission OM&A expense into line and station related. The line related OM&A is sub-functionalized to main grid, 230 & 138 kV radials, & 72 kV radials using the transmission line assets plant in service sub-function. The station related OM&A expense is sub-functionalized using station assets plant in service by sub-function.

- Distribution OM&A is functionalized to distribution and customer services using a combination of staff input and detailed cost centre OM&A reports. The same analysis provides the sub-functionalization within the distribution and customer services functions.

- Metering Services OM&A was moved from Customer Services to Transmission & Distribution in 2013 but is still functionalized to Customer Services.

Customer Services Business Unit:
The OM&A expense for the Customer Services Business Unit is functionalized to customer services. The sub-functionalization is provided directly from cost centre Operation, Maintenance and Administration (OM&A) reports.

Customer Services - Bad Debt Expense:
The bad debt expense is assigned to the customer collections sub-function with the Customer Services function.

President / Board:
Assigned to functions and sub-functions based on the functionalization and sub-functionalization of the sum of the OM&A expense for the Power Production, Transmission and Distribution, and Customer Service business units and support groups.

Corporate & Financial Services:
Functionalized based on employee head count by Business Unit and Support Group.

Corporate & Financial Services – Insurance Premiums & Insurable Losses:
Functionalized based on Breakdown from SaskPower Risk Management & Insurance department staff.

Asset Management, Planning & Sustainability:
Asset Management, Planning & Sustainability was previously called Resource Planning/Planning, Environment and Regulatory Affairs (PERA). It is made up of 4 cost centres: Generation Asset Management and Supply Planning, Transmission Asset Management and Planning, Distribution Asset Management and Planning, and Environment. The Planning cost centres are assigned to functions and sub-functions based on the functionalization and subfunctionalization of the sum of the OM&A expense for the three Business Units and Support Groups. The Environment cost centre moved to Resource Planning from Human Resources in 2015 and is allocated based on an employee analysis which was done by SaskPower Environment department staff. The Shand Greenhouse is embedded within the Environment cost centre and is functionalized to Generation.

Carbon Capture & Storage (CSS):
The OM&A expense for Carbon Capture & Storage (CSS) is embedded within the Power Production business unit and is functionalized to Generation.

General Council / Land:
Assigned to functions and sub-functions based on the functionalization and sub-functionalization of the sum of the OM&A expense for the three Business Units and Support Groups. The Electrical and Gas inspections OM&A was previously reported here but was removed in 2021 and is no longer under the umbrella of SaskPower.

Safety:
Functionalized based on the safety department staff assignments to the Business Units and Support Groups and then sub-functionalized using the OM&A sub-functionalization within each function.

Technology & Security (formerly Corporate Information & Technology):
Technology & Security operations, maintenance and administration expense is separated into personal computer related and Business Unit related. The personal computer related is functionalized using employee headcount. The Business Unit related is functionalized using information from the cost centre report. Sub-functionalization is completed using OM&A within each function.

Human Resources:
Functionalized based on the employee head count by Business Unit and then sub-functionalized using the OM&A sub-functionalization within each function.

Commercial & Industrial Operations:
Commercial & Industrial Operations is a newly formed department made up of 4 cost centers: Customer Relations, Coal Combustion Products, Fuel Supply and NorthPoint. The Customer Relations cost center was previously reported in Customer Services and continues to be functionalized to Customer Service. Coal Combustion was previously reported in the Power Production business unit and continues to be functionalized to Generation. The Fuel Supply cost center was previously reported in Resource Planning and continues to be functionalized to Generation. NorthPoint previously was reported in Operations and continues to be functionalized to Generation.

Procurement & Supply Chain
Procurement & Supply chain is made up of 3 cost centers: Supply Chain, Properties & Shared Services, and Contract Management. Supply Chain and Properties & Shared Services are functionalized based on the employee head count by Business Unit and then sub-functionalized using the OM&A sub-functionalization within each function. Contract Management is functionalized to Generation. The Logistics area was moved to Procurement & Supply Chain in 2015 from Distribution, however, based on Logistics' close relation to Distribution; their OM&A is still being calculated and functionalized within Distribution.

2.5 - Depreciation & Depletion

The functionalization of depreciation and depletion is the same as for plant in service and accumulated depreciation above.

2.6 - Corporate Capital Tax

Corporate capital tax is prorated to functions and sub-functions using resultant rate base functionalization.

2.7 - Grants in Lieu of Taxes

Grants in lieu of taxes are assigned to the grants in lieu of taxes sub-function within the generation function.

2.8 – Miscellaneous Tax

The miscellaneous tax expenses have been grouped into the following categories using cost center reports:

- **Power production related:**
  Functionalized to generation.

- **Fuel supply related:**
  Functionalized to generation.

- **Gas & electric inspections related:**
  Functionalized to customer services.

- **Vehicles and equipment related:**
  Functionalized using the vehicles and equipment plant functionalization as reported in Section 1.1.

- **Buildings related:**
  Functionalized using the buildings plant functionalization as reported in Section 1.1.

- **Corporate related:**
  Functionalized using total OM&A expense.

2.9 - Other Income

Other income is treated as an offset to expenses in the cost of service model. Other income has been grouped into the following categories using accounting records.

- **Customer services payment income:**
  Assigned to the billing, customer accounts and collections sub-functions within customer services.

- **Meter reading income:**
  Assigned to the meter reading sub-function within the customer services function.

- **Gas & electric inspections income:**
  Previously assigned to the Customer Service sub-function within the customer services function. This revenue centre has been removed in 2021 as it is no longer under the umbrella of SaskPower.

- **Transmission related income:**
  Assigned to sub-functions within the transmission function using transmission OM&A expense.

- **Distribution related income:**
  Assigned to sub-functions within the distribution function using distribution OM&A expense.

- **Clean Coal Test Facility Revenue:**
  Previously assigned to the load and losses sub-functions within generation using fuel expense. This revenue centre has been removed in 2021 as no revenue has been incurred.

- **Clean Coal Project Credits:**

Assigned to the load and losses sub-functions within generation using fuel expense.

- **CO2 Sales & Penalties:**
  Assigned to the load and losses sub-functions within generation using fuel expense.

- **Miscellaneous Other Income:**
  Assigned to functions and sub-functions based on the functionalization and sub-functionalization of the sum of the OM&A expense for the three Business Units and Support Groups.

- **Customer Contribution Revenue**
  As per adoption of IFRS, contributions in aid of construction and reconstruction are now recognized immediately as Other Income when the related fixed asset is available for use and is functionalized to transmission and distribution.

- **Green power premium:**
  Assigned to the load and losses sub-functions within generation using fuel expense.

- **Flyash & Wind Power Sales:**
  Assigned to the load and losses sub-functions within generation using fuel expense.

- **Consulting & Contracting Services:**
  Assigned to functions and sub-functions based on the functionalization and sub functionalization of the sum of the OM&A expense for the Power Production, Transmission and Distribution, and Customer Service business units and support groups.

2.10 - Return on Rate Base

The functionalization and sub-functionalization of return on rate base is determined by the functionalization of rate base above as the RORB is the simple calculation of rate base multiplied by the return on rate base in percent.

CLASSIFICATION

The classification process splits the functionalized costs into the parameters of service, which are:

Demand – costs that vary with the kilowatt demand imposed on the system, such as the demand component of production, transmission and distribution systems.

Energy – costs that vary with the energy or kilowatt-hours provided by the utility, such as the cost of fuel and variable generation costs.

Customer – costs related to the number of customers served, such as customer billing, meter reading, customer service and the capital costs of meters and services.

A discussion of the classification of each of the functionalized costs is as follows:

Generation:

SaskPower generation rate base and expense is classified as either demand or energy related. The classification methodology currently used by SaskPower for generation rate base and depreciation expenses, including wind, is the Average & Excess Demand method, based on the NARUC Electric Utility Cost Allocation manual. The rationale behind this method 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.

The assets and expenses associated with Purchased Power Agreements (PPA's) are classified to demand and energy using the capacity and energy payments for each plant.

The fuel expense for SaskPower units is classified 100% to energy. The classification of purchased power and import expense to demand and energy is done using the capacity and energy payments to suppliers. The classification of export and net electricity trading revenue is classified 100% to energy. Generation operating, maintenance and administrative (OM&A) expenses are classified using an analysis of fixed and variable OM&A by type of generating plant.

The expenses and income associated with fly-ash sales (now called Coal Combustion Products) are classified as energy related.

Coal Reserves:
SaskPower coal reserves are classified energy related.

Shand Greenhouse:
The Shand Greenhouse assets, OM&A and depreciation expenses are classified using the classification of all SaskPower generation.

NorthPoint:
The OM&A expense and other revenue associated with NorthPoint are classified 100% to energy related.

Transmission:
Transmission facilities are built to meet the maximum system coincident demand requirements of customers and are classified 100% to demand.

Distribution:
Substations are classified 100% to demand-related cost. Three phase feeders are classified 100% to demand-related cost. Both urban and rural single-phase primary lines are classified 30% to demand-related and 70% to customer-related cost. Line transformers are classified 65% to demand-related and 35% to customer-related cost based upon the Minimum System Method. All secondary lines, services, and meters are classified 100% as customer-related cost. Streetlighting is directly assigned as customer-related.

Customer:
Customer related costs are classified 100% to customer.

ALLOCATION

Allocation is the apportioning of functionalized and classified rate base and expense to customer classes.

Customer Classes: The following is a list of the customer classes currently served by SaskPower, to which the functionally classified rate base and expense are allocated.

- Residential
- Farms
- Commercial
- Power - Published Rates
- Power - Contract Rates
- Oilfields
- Streetlights
- Reseller

An explanation of the allocation process by function is as follows:

Generation:
The energy related rate base and expenses such as fuel and cost of coal are allocated to the customer classes by the energy consumed by each class plus an estimate of losses. The demand related rate base and expenses are allocated by the 2CP (coincident peak) method, plus an estimate of losses. The 2CP method allocates costs to customer classes based upon the contribution which the respective customer class makes to the average of SaskPower's winter and summer seasonal peaks. The winter seasonal peak load is SaskPower's largest demand calculated on an hourly interval basis during the months of November to February. The summer seasonal peak load is SaskPower's largest demand calculated on an hourly interval basis during the months of June to September. The months of March, April, May and October are considered "shoulder" months and do not contribute to the seasonal peak periods. Allocation factors are developed as the ratio of the class load at the time of the average seasonal peak to the total load.

Transmission:
All of the transmission functions are classified as demand and are allocated using the 2CP (coincident peak) method as aforementioned.

Distribution:
The demand functions within distribution use a combination of the 2CP method and the Maximum Diversified Class Demands (MDD) method. The MDD method allocates rate base and expense responsibilities based on the ratio of the sum of the maximum demands of all customers within a class regardless of when it occurs, during a specified period. Only the transformers' function uses the MDD methodology; all other functions use the 2CP methodology.

The customer functions within distribution use a combination of methodologies depending on the sub-function. Urban and rural laterals are allocated to customer classes based on the number of urban and rural customers supplied through laterals. Customer related transformers are allocated using the number of customers supplied through transformers. Distribution services are allocated directly to customer classes. Meters are allocated by the number of metered customers weighted by the installed cost of a meter. Streetlight related rate base and expenses are allocated directly to streetlights.

Customer Services:
The customer services functions are allocated to customer classes based on the weighted number of customers in the class. This weighting is based on annual surveys of how much time departments spend working with each customer class.

Customer Contributions:
These contributions are allocated back directly to the customer classes which made the contribution.

Load Data
Customer load data is obtained for each class from the best available sources. Hourly Residential, Farm, Commercial, and Oilfield load data were obtained from a statistically valid sample size of meter readings from actual customer's interval metered sites. The results for the customer types in each of these classes are then extrapolated to the entire class in proportion to the classes' billing determinants. Typical load shapes for the Streetlight class were gathered from a neighbouring utility.
Power Class loads were analyzed based on hourly meter readings from actual customer's interval metered sites.

Loss Study
The purpose of a loss study is to properly quantify and assign to the appropriate customer class the electrical energy and demand losses in the various segments of the system. The starting point is the total energy loss in GWh, calculated as the difference between input to the system measured at the generator and output measured at the customer's meter.

The loss analysis relies, to a significant extent, upon the loss analysis prepared by the Network Planning department, which includes a load-flow analysis of the transmission system. The load-flow analysis provides both energy and demand losses.

Distribution system losses are apportioned to the various components in proportion to loss percentages generally associated with those elements of the distribution system.

A spreadsheet program is used to apportion the energy losses to the various class loads, recognizing that losses at one level of the system increase losses at another level.

Appendix B: Utilities Surveyed

Canadian

BC Hydro

ATCO Electric

Manitoba Hydro

Hydro One Networks Inc.[7]

Hydro Quebec

Newfoundland Power

New Brunswick Power

Nova Scotia Power

US Utilities

Montana-Dakota Utilities

Georgia Power

[7] In Ontario the electricity market was deregulated in April 1999. OPG generates electricity and Hydro One transmits and distributes electricity

	Method to classify Generation assets and expenses
SaskPower	System load factor 25% demand / 75% energy
BC Hydro	55% demand, 45% energy using a system load factor approach
ATCO	NA
Manitoba Hydro	Eight-year average system load factor 39.9% demand
Hydro One	NA
Hydro Quebec	Utilization factor during 300 hours - 69.4% demand
NL Power	System load factor 45.7% demand
NB Power	# CP and Average 49.2% demand
NS Power	Hydro investments are demand Other demand related based on system load factor - overall 31.4% demand
Georgia Power	100% demand
Montana-Dakota Utilities	Net plant 100% demand, O&M 33% demand

	Hydroelectric	Baseload Steam	Combustion Turbine	Transmission	Sub-transmission
SaskPower	25% demand/ 75% energy	25% demand/ 75% energy	25% demand/ 75% energy	100% demand	100% demand
BC Hydro	55% demand/45% energy	100% demand	100% demand	100% demand	100% demand
ATCO	NA	NA	NA	AESO bill into demand/customer	30% to 35%
Manitoba Hydro	39.9% demand	39.9% demand	39.9% demand	100% demand	100% demand
Hydro One	NA	NA	NA	100% demand	100% demand
Hydro Quebec	NA	NA	NA	Rate base 100% demand, Expenses 24.9% demand	100% demand
NL Power	System load factor 45.7% demand	NA	NA	100% demand	100% demand
NB Power	49.2% demand	49.2% demand	49.2% demand	100% demand	100% demand
NS Power	100% demand	31.4% demand	100% demand	Currently 46.2% demand	Currently 46.2% demand
Georgia Power	100% demand	100% demand	100% demand	100% demand	100% demand
Montana-Dakota Utilities	100% of net plant is demand related and 33% of O&M is demand related	100% of net plant is demand related and 33% of O&M is demand related	100% of net plant is demand related and 33% of O&M is demand related	100% demand	100% demand

	Distribution Substations	Primary Lines	Distribution Transformers	Line Transformers	Secondary Lines	Services Fixed costs
SaskPower	100% demand	100% demand	65% demand/ 35% customer	100% customer	35% demand (urban) 65% demand (rural)	100% customer
BC Hydro	100% demand	100% demand	50% demand/50% customer	50% demand/50% customer	50% demand/50% customer	50% demand/50% customer
ATCO	100% demand	100% demand	40% to 60% demand (currently 47.6%)	40% to 60% demand (currently 47.6%)	30% to 35% demand	100% customer
Manitoba Hydro	100% demand	100% demand	100% demand	100% demand	100% demand	100% customer
Hydro One	100% demand	52.2% demand	38.1% demand	38.1% demand related	52.2% demand related	100% customer
Hydro Quebec	100% demand	100% demand	100% demand	79.8% demand	79.8% demand	100% customer
NL Power	100% demand	63% demand	72% demand	72% demand	63% demand	100% customer
NB Power	100% demand	50% demand	75% demand	75% demand	50% demand	100% customer
NS power	100% demand	62.5% demand	100% demand	100% demand	17.6% demand	100% customer
Georgia Power	100% demand	82% demand	100% demand	75% demand	75% demand	100% customer
Montana-Dakota Utilities	100% demand	100% demand	100% demand	20% Demand	100% demand	100% customer

	Meters	Method used to determine distribution customer related	Method used to allocate generation demand costs	Method used to allocate transmission demand costs	Method used to allocate sub-transmission demand costs	Method used to allocate distribution stations demand costs
SaskPower	100% Customer	Minimum System	2CP	2CP	2CP	2CP
BC Hydro	100% customer	Zero Intercept for transformers. Minimum System for secondary	4CP	4CP	4CP	Class NCP
ATCO	100% customer	Average of Zero intercept and Minimum system	NA	Allocated POD Capacity Demand and AEIS CP Summary Demand	EDLA study (Energy, Demand Loss Analysis) [Annual POD NCP Demand]	EDLA study (Annual POD NCP Demand)
Manitoba Hydro	100% customer	PUB order 100% demand	1 CP on top 50 winter hours	1 CP on top 50 winter hours	1 CP on top 50 winter hours	Class NCP
Hydro One	100% customer	Minimum System	NA	12 CP	12 CP	CP and NCP
Hydro Quebec	100% customer	Minimum System	Highest 300 hours	1CP	1CP	1NCP
NL Power	100% customer	Minimum System for lines, Zero Intercept for transformers	1 CP	1 CP	1 CP	NCP
NB Power	100% customer	Historical	3 CP	1 CP	1 CP	12 NCP
NS Power	100% customer	Judgement 50/50	3 winter CP	3 winter CP	3 winter CP	1 NCP
Georgia Power	100% customer	Zero intercept	12 CP	12 CP	4 CP	4-CP
Montana-Dakota Utilities	100% customer	Minimum System	4 Coincident Peak 75% Demand/25% Energy	12 CP	CP	CP

	Method used to allocate distribution primary lines demand costs	Method used to allocate distribution transformers demand costs	Method used to allocate distribution secondary lines demand costs	Method used to allocate distribution stations customer costs	Method used to allocate distribution primary lines customer costs	Method used to allocate distribution transformers customer costs
SaskPower	2 CP	Class NCP	Class NCP	NA (100% demand)	# of customers	# of customers
BC Hydro	NCP	NCP class	NCP class	# of customers	# of customers	# of customers
ATCO	An EDLA study (Energy, Demand Loss Analysis) is used to allocate costs to rate classes (Annual POD NCP Demand)	Weighted Property Plant & Equipment (Transformers)	Weighted Property Plant & Equipment (Poles & Conductor)	NA (100% demand)	NA (100% demand)	Property Plant & Equipment (Transformers) weightings depending on customer counts
Manitoba Hydro	Class NCP	Class NCP	Class NCP	NA (100% demand)	NA (100% demand)	NA (100% demand)
Hydro One	NCP	NCP	NCP	NA (100% demand)	Customer count	Customer count
Hydro Quebec	1NCP	1NCP	1NCP	# of customers	# of customers	# of customers
NL Power	NCP	NCP	NCP	NA (100% demand)	Equal Weighting	Equal Weighting
NB Power	12 NCP	12 NCP	12 NCP	N/A	# of customers	# of customers
NS Power	1 NCP	1 NCP	1 NCP	NA (100% demand)	Weighted # of customer	NA (100% demand)
Georgia Power	NCP	NCP	Average # of Customers	NA (100% demand)	Average # of Customers	NA (100% demand)
Montana-Dakota Utilities	NCP	NCP	NCP	NA (100% demand)	NA (100% demand)	NA (100% demand)

	Method used to allocate distribution secondary lines customer costs	Method used to allocate services customer costs	Method used to allocate Meter customer costs
SaskPower	# of customers	Direct allocation	Weighted Customer Count
BC Hydro	# of customers	# of customers	# of customers
ATCO	Property Plant & Equipment (Poles & Conductors) weightings depending on customer counts	Weighted Customer Count	Weighted Customer Count
Manitoba Hydro	NA (100% demand)	Weighted Customer Count	Weighted Customer Count
Hydro One	Customer Count Secondary	Weighted Customer Count	Weighted Customer Count
Hydro Quebec	# of customers	Weighted # of customers	Weighted # of customers
NL Power	Equal Weighting	Based on typical costs to provide drops to customers within each class	Based on typical costs to provide drops to customers within each class
NB Power	# of customers	Weighted # of customers	Weighted # of customers
NS power	Weighted number of customers	Weighted number of customers	Weighted # of customers
Georgia Power	Average # of customers	Average # of customers	Average # of customers
Montana-Dakota Utilities	# of customers	Number of customers	Weighted # of customers

APPENDIX C: ELENCHUS TEAM QUALIFICATIONS

JOHN D. TODD

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PRESIDENT

John Todd has specialized in government regulation for over 35 years, addressing issues related to price regulation and deregulation, market restructuring to facilitate effective competition, and regulatory methodology. Sectors of primary interest in recent years have included electricity, natural gas and the telecommunications industry. John has assisted counsel in over 275 proceedings and provided expert evidence in over 150 hearings. His clients include regulated companies, producers and generators, competitors, customer groups, regulators and government.

PROFESSSIONAL OVERVIEW

Founder of Elenchus Research Associates Inc. (Elenchus) **2003**

- ERAI was spun off from ECS (see below) as an independent consulting firm in 2003. There are presently twenty-five ERAI Consultants and Associates. Web address: www.elenchus.ca

Founded the Canadian Energy Regulation Information Service (CERISE) **2002**

- CERISE is a web-based service providing a decision database, regulatory monitoring and analysis of current issues on a subscription basis. Staff are Rachel Chua and rotating co-op students. Web address: www.cerise.info

Founded Elenchus (Econalysis) Consulting Services, Inc. (ECS) **1980**

- ECS was divested as a separate company in 2003

EDUCATION

1975 Masters of Business Administration (Economics and Management Science), University of Toronto

1972 Bachelors of Applied Science (Electrical Engineering), University of Toronto

PRIOR EMPLOYMENT

Ontario Economic Council, Research Officer (Government Regulation) **1978 - 1980**

Research Assistant, Univ. of Toronto, Faculty of Management Studies **1973 - 1978**

Bell Canada, Western Area Engineering **1972 – 1973**

REGULATORY/LEGAL PROCEEDINGS

Before the Ontario Energy Board

John Todd has provided expert assistance in more than 65 proceedings before the Ontario Energy Board from 1991 to 2022. He has presented evidence in more than 25 of these cases. Recent cases include rate applications for the EPCOR Natural Gas LP (and the predecessor company NRG) and evidence on the *Cost Allocation and Rate Design for the IESO Usage Fee* for the Independent Electricity System Operator.

Before the Public Utilities Board of Manitoba

John has provided expert assistance in a total of 46 proceedings before the Public Utilities Board of Manitoba from 1990 to 2020. He has presented evidence in 23 of these cases. He was retained by the Manitoba Public Utilities Board as an Independent expert consultant to review aspects of Manitoba Hydro's Needs for and Alternatives to (NFAT) its Preferred Development Plan. He also served as a Board advisor for the Review of Efficiency Manitoba's 2020-2023 DSM Plan.

Before the British Columbia Utilities Commission

John has provided expert assistance in more than 30 proceedings before the British Columbia Utilities Commission from 1993 to 2021. He has presented evidence in ten cases. Recently he was retained (with Michael Roger) by the BCUC as its independent expert consultant to review FortisBC Energy Inc. cost allocation and rate design methodology.

Before the Régie de l'énergie

John has provided expert assistance in more than twelve proceedings before the Régie de l'énergie from 1998 to 2022. He has presented evidence in nine of these cases. He was retained with Cynthia Chaplin to prepare *Report for the Régie de l'énergie, Performance Based Regulation: A Review of Design Options as Background for the Review of PBR for Hydro Quebec Distribution and Transmission Divisions.* He is currently engaged in another cost allocation review project for the Régie as an independent expert reviewing the cost allocation methodology of Energir.

Before the Alberta Utilities Commission (and formerly the Alberta Energy and Utilities Board)

John has provided expert assistance in of five proceedings before the Alberta Utilities Commission and its predecessor since 2000. In 2020 he was engaged for rate design work by an Alberta utility.

Before the Newfoundland & Labrador Board of Commissioners of Public Utilities

John has provided expert assistance in a total of nine proceedings from 2005 to 2021. He has presented evidence most recently in Newfoundland Power's 2022 Capital Budget Application.

Before the New Brunswick Energy and Utilities Board

John has provided expert assistance in a total of nine proceedings before the New Brunswick Energy and Utilities Board from 2007 to 2021. He has presented evidence in three cases. Recent proceeding he participated in were the *2019-20 General Rate Application* and NB Power's reviews of its cost allocation methodology and rate design issues.

Before the Nova Scotia Utility and Review Board

John has provided expert assistance in a total of nine proceedings before the Nova Scotia Utility and Review Board from 2008 to 2021. He has presented evidence in four cases. The most recent work related to *Efficiency One, Updated Cost Allocation Methodology* and Nova Scotia Power's 2022-2024 General Rate Application.

Before the National Energy Board (NEB)

John has provided expert assistance in one proceeding before the NEB, during 1999. The proceeding was in regards to *BC Gas, Southern Crossing Project.*

Before the Canadian Radio-television and Telecommunications Commission (CRTC)

John has provided expert assistance in 47 proceedings before the Canadian Radio-television and Telecommunications Commission from 1990 to 2020. He has presented evidence in 13 of these cases. The participated in a *Review of Basic Telecommunications Services, Consultation CRTC 2015-134* and prepared evidence was filed in the current Review of the Approach to Rate Setting for Wholesale Telecommunications Services (CRTC 2020-131).

Before the Ontario Securities Commission

John provided expert assistance on behalf of the Director of Investigation and Research, Combines Investigation Act in four proceedings before the Ontario Securities Commission from 1981 to 1985. He presented evidence in each case including evidence on Industry structure and the form of regulation in the OSC's *Securities Industry Review.*

Before the Ontario Municipal Board

John has provided expert evidence and assistance in two proceedings before the Ontario Municipal Board in 1992 and 1995. In 1995, he assisted in a case regarding an *Appeal of Boundary Expansion by Lincoln Hydro and Electric Commission*, with an affidavit prepared on the tests for boundary expansions.

Before the Supreme Court of Ontario

John has presented evidence in one proceeding before the Supreme Court of Ontario, in 1990. The case related to the *Challenge of the Residential Rent Regulation Act (1986) under the Canadian Charter of Rights and Freedoms.* Evidence: The impact of rent regulation on Ontario's rental housing market.

Before the Saskatchewan Court of Queen's Bench

John has presented evidence in one proceeding before the Saskatchewan Court of Queen's Bench, in 1993. The evidence was regarding market dynamics and competition policy. John (with Michael Roger) has also conducted the two most recent reviews of SaskPower's cost allocation methodology and presented the results to the Saskatchewan Rate Review Panel.

Non-Hearing Processes

John has provided expert assistance more than a dozen non-hearing processes since 1997 to the following Ontario Energy Board, British Columbia Gas, the British Columbia Utilities Commission, the New Brunswick Department of Energy, SaskPower, the Government of Vietnam, and more.

Commercial Arbitrations and Lawsuits

John has provided expert assistance in seven commercial arbitrations and lawsuits between 2004 and 2022.

Facilitation Activities

John has undertaken numerous strategic planning and visioning sessions (some with co-facilitators) for the Executive and/or Board of Directors of regulated companies between 2000 and 2020. He has also facilitated six stakeholder processes for regulators and utilities from 2000 through 2017.

Other Regulatory Issues Researched

John has completed (with collaborators in some cases) over 20 studies for industry associations, regulators, utilities and other entities outside of hearing processes

SELECTED PRESENTATIONS

- Utility Cost Recovery in an Era of Ageing Infrastructure, Technological Change and Increasing Customer Service Expectation, CEA Legal Comm. & Regulatory Innovations Task Group (June 2016)
- Productivity Benchmarking Panel at the CEA Electric Utility Workshop (May 2016)
- Funding Utility Innovation at the CEA Electric Utility Workshop (May 2016)
- MEARIE Training Program, Regulatory Essentials for LDC Executives (several years)
- Issue in Regulatory Framework for Tenaga Nasional Berhad, Indonesia (with Cynthia Chaplin & London Economics) (2015)
- Witness Training for electric utilities 2014 - 2020
- "Innovations in Rate Design", CAMPUT Training Session, Annually 2010-2013
- "Cost of Service Filing Requirements" (2010) 2nd Annual Applications Training for Electricity Distributors, Society of Ontario Adjudicators and Regulators in cooperation with the OEB
- "Green Energy Act" (2010) 2nd Annual Applications Training for Electricity Distributors, Society of Ontario Adjudicators and Regulators in cooperation with Ontario Energy Board
- "Rate Design", CAMPUT Training Session, Annually 2009- 2013
- "How to Build Transmission and Distribution to Enable FiT: The Role of Distributors", EUCI Conference on Feed in Tariffs, Toronto, Sept. 2009
- "Distributor Mergers and Acquisitions: Potential Savings", 2007 Electricity Distributors Assoc.
- "Beyond Borders" Regulating the Transition to Competition in Energy Markets (with Fred Hassan), EnerCom Conference March 2006.

SELECTED OTHER ACTIVITIES

- Chairman of the Board of Directors of the Ontario Energy Marketers Association (formerly the Direct Purchase Industry Committee) and Executive Director of the Association.
- Former invited participant in the Ontario Energy Board's External Advisory Committee.
- Former Member of the Board of Directors of East Toronto Community Legal Services.
- Organizing Committee for the Concert for Inclusion in support of ParaSport Ontario
- Numerous appearances on CBC radio and television commenting on energy industry issues, competition, regulation and mergers in the Canadian economy.

CLIENTS

Over seventy private sector companies, including utilities

Fifteen industry and other associations

Over thirty 30 consumers' associations and legal clinics

Government

- Five Regulatory Tribunals
- Six Federal departments
- Fourteen Provincial departments, commissions and agencies
- Thirteen municipal and other departments/entities

ANDREW BLAIR

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SENIOR CONSULTANT

Andrew Blair has six years of experience as a research analyst and consultant in electricity and gas utility price regulation. He regularly prepares load forecasts for electricity and natural gas utility cost of service applications in Ontario and provides cost allocation and rate design support to utilities across Canada.

Andrew regularly prepares models, reports, and other written evidence for utility public application filings. He appears before the New Brunswick Energy & Utilities Board as New Brunswick Power's cost allocation subject matter expert in annual general rate applications and has appeared before the Ontario Energy Board on an expert panel on transmission cost allocation. Andrew has created and developed cost allocation and rate design models, including for Monserrat Utilities and Ontario's Independent Electricity System Operator. He is an instructor in MEARIE's Regulatory Specialist Certificate program in the area of load forecasting, cost allocation, and rate design. He previously worked for the Ontario provincial government over a seven-year period as a trust analyst and a trust accountant. Andrew has a Master's Degree in Economics from Carleton University and a Bachelor's Degree in Economics and Financial Management from Wilfrid Laurier University.

PROFESSIONAL OVERVIEW

Elenchus Research Associates — **January 2016 - Present**
Research Analyst

- Prepare load forecasts for electricity and natural gas utilities
- Design and prepare cost allocation and rate design models and evidence
- Research regulatory filings and common practices across jurisdictions and regulators
- Provide research and modeling support for economic feasibility studies
- Prepare evidence, interrogatories, cross-examination, and submissions for regulatory hearings

Office of the Public Guardian and Trustee — **May 2012 – June 2013**
Trust Analyst — **Summers 2010 & 2011**

- Designed estate allocation and payment disbursement system
- Summarized and analyzed aggregate account information
- Allocated interest and fees to close out accounts
- Researched Public Guardian clients' files and family histories to determine estate beneficiaries
- Located beneficiaries and distributed estates

Co-op Student 2006
Accountant of the Superior Court of Justice **Summers 2007 - 2009**
Trust Accounting Officer

- Reconciled client account balances
- Located clients with an outstanding balance with the court
- Updated client account balances as well as pension and disability allowances

EDUCATION

June 2014	Master of Arts, Economics, Carleton University
June 2012	Bachelor of Arts, Economics and Financial Management, Wilfrid Laurier University

Selected Specific Project Experience:

Cost of Service and Tariff Design

- **New Brunswick Power** – prepared cost allocation evidence for annual general rate applications. Contributed to export reports on cost allocation issues and proposed methodology changes for NB Power. Appeared before New Brunswick Energy & Utilities Board as NB Power subject matter expert in area of cost allocation.
- **Montserrat Utilities Ltd. –** for an integrated resource plan, cost of service and tariff study led by HATCH, created a cost allocation model to attribute costs to electricity, water, and wastewater services and to rate classes within each service. Proposed changes to tariff structures.
- **Burlington Hydro -** prepared cost allocation and rate design models and evidence for cost of service application to OEB.
- **Grimsby Power Inc. -** prepared cost allocation and rate design models and evidence for cost of service application to OEB.
- **SaskPower -** prepared rate design analysis for proposed standby rates in report submitted to the Saskatchewan Rate Review Panel.
- **EfficiencyOne Nova Scotia –** prepared and revised long-term rate and bill impact analysis model for Nova Scotia demand-side management programs.
- **Greater Sudbury Hydro -** prepared cost allocation and rate design models and evidence for cost of service application to OEB.
- **Lakefront Utilities -** prepared 40-year cost of service and bill analysis for prospective natural gas utility along the north shore of Lake Superior. Also prepared bill-smoothing and rate mitigation analysis.
- **Hydro Ottawa -** prepared cost allocation and rate design models and evidence for cost of service application to OEB.

- **Hydro One Transmission -** prepared report on export transmission service rates based on cost allocation between domestic and export services.
- **Independent Electricity System Operator -** prepared annual cost allocation and usage fee design models for revenue requirement submissions.
- **Power Worker's Union –** act as intervenor on behalf of the Ontario Power Worker's Union in OEB consultations and rate cases of large utilities with PWU-represented employees. Reviewed evidence, prepared interrogatories and submissions on behalf of the PWU in rate cases for Hydro One, Ontario Power Generation, Toronto Hydro, and Alectra Utilities.
- **MEARIE Regulatory Specialist Training** – conducted training in areas of cost allocation and rate design for cost of service applications to employees of Ontario distribution utilities.

Load Research

- **Burlington Hydro** – prepared a load forecast for Burlington's cost of service application to the Ontario Energy Board ("OEB"), including various scenarios related to the COVID-19 pandemic. Prepared peak demand analysis of various rate classes to be used in cost allocation.
- **Grimsby Power Inc.** – prepared a load forecast for Grimsby Power's cost of service application to the OEB.
- **EPCOR Natural Gas LP –** prepared 5-year natural gas throughput forecasts for its natural gas service territory in Aylmer, Ontario. The throughput forecasts include scenario analyses and are prepared regularly for gas supply plans submitted to the OEB.
- **EnWin Utilities** - prepared a load forecast for EnWin's cost of service application to the OEB.
- **Erie Thames Powerlines -** prepared a load forecast for Erie Thames's cost of service application to the OEB and peak demand analysis of various rate classes for cost allocation.
- **Essex Powerlines** - prepared a load forecast for Essex's cost of service application to the OEB.
- **Halton Hills Hydro** – Supported Halton Hills's cost of service in load forecasting and conservation and demand management reporting.
- **Greater Sudbury Hydro** - prepared a load forecast for Greater Sudbury's cost of service application to the OEB.
- **Lakefront Utilities** - contributed to 40-year natural gas throughput and peak design day forecasts for prospective natural gas distribution utility.
- **MEARIE Regulatory Specialist Training** – conducted training in area of load forecasting for cost of service applications to employees of Ontario distribution utilities.

APPENDIX D: RESPONSE TO STAKEHOLDER QUESTION

2023 Cost of Service Methodology Review

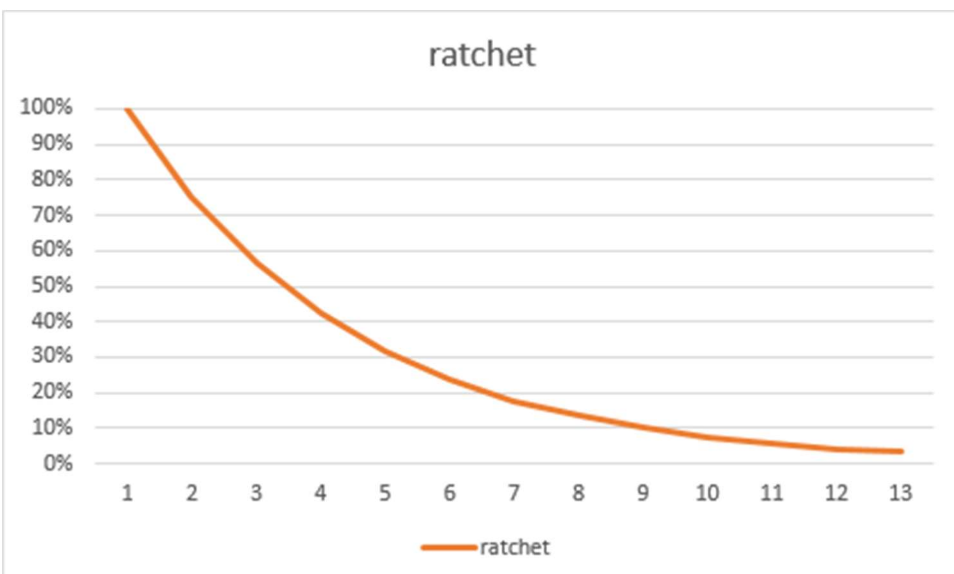
QUESTIONS & ANSWERS

1. Cenovus Energy Inc.

SaskPower has several rates that essentially set ratchets on ratchets, for a site that has a rate of reduction in their load of greater than 25% per year over several years. The wording of the billing demand definition below (seen in multiple rates) results in a multi-year ratchet based on year one's metered demand. The graph below shows how the ratchet is equal to 75% of year one's metered demand in year 2, 56% of year one's metered demand in year 3, 42% of year one's metered demand in in year 4, and so on.

Can you explain what the objectives are for this multi-year ratchet and if there are other ways to achieve those objectives?

> **BILLING DEMAND**
>
> The monthly billing demand is the monthly recorded demand, but the billing demand shall not be less than 75 per cent of the maximum billing demand in the preceding 11 months.



The table below shows the percentages graphed in the y-axis of the graph above for the first eight years.

	year 1	year 2	year 3	year 4	year 5	year 6	year 7	year 8
Ratchet on year x based on year 1 metered demand	100%	75%	56%	42%	32%	24%	18%	13%

SASKPOWER RESPONSE:

Demand ratchets are a common rate design tool used by electric utilities to reduce the risks of serving certain types of customers who have volatile demand throughout the year. A utility invests in lines and other facilities to meet the customer's expected demand. A significant decline in their demand severely diminishes the utility's ability to recover the fixed costs related to the installation of these facilities. The imposition of a demand ratchet allows SaskPower to recover the cost of its investment to serve that customer, even when the customer's demand falls below expectations and by establishing a minimum bill that covers a portion of fixed costs regardless of the customer's actual energy consumption.

Ratchets have several objectives:

1) They tend to encourage customers to increase their annual load factor, which often promotes favourable system load characteristics.

2) They can improve the equity of a utility's rate design by protecting other customers from additional costs due to stranded generation, transmission and distribution assets when a customer reduces load.

   For example, a transformer may be for the use of one customer who has a large load for only two months and is inoperative the rest of the year. If a demand ratchet is not imposed, the fixed costs of that transformer will be recovered through other customers during the 10 months that the customer is off the system. A ratchet provides a mechanism to protect other customers by ensuring a customer with variable demand pays its causal costs.

3) They help stabilize revenues and ensure utilities recover enough revenue from customers whose demands fluctuate throughout the year.

The demand ratchet is applied differently to different types of customers based on risk. Smaller General Service and Farm customers have smaller demand ratchets because the risk of stranded generation and transmission assets from this class is less than when compared to larger Power class customers. For Power and Large Oilfield classes, the demand ratchet is applied to their Billing Demand, which is their monthly Recorded Demand, but it cannot be less than 75 per cent of the maximum Billing Demand in the preceding 11 months.

As noted in the question, since the ratcheted minimum demand charge is 75 per cent of Billing Demand rather than Recorded Demand, the ratchet impacts may extend beyond 11 months if the customer sustains prolonged load reductions. This is done for the following reasons:

- There is a larger risk of stranded generation and transmission assets from the large loads.
- The lead times for new generation and transmission assets are long.
- We are obligated to hold customer's capacity for planning purposes for two years.

An alternative measure to achieve these objectives would be to charge the customer more for their initial connection to SaskPower's grid when they apply for service. This way, if the customer fails to meet their planned load requirements or leaves the system prematurely, the risk exposure to our remaining customers remains relatively low.

It should be noted that it is rare for a customer in this rate class to incur a large load reduction over a prolonged period that would result in the ratchet being applied beyond 11 months and SaskPower reserves the right to reset a demand ratchet.

SRRP Q77 Reference: Proposed Rates Revenue to Revenue Requirement Ratios

a) Please provide the revenues and revenue requirement breakdowns by class in dollars supporting the calculation of the 2025/26 revenue to revenue requirement ratios illustrated in the first table on page 35 of the application and the 2026/27 revenue requirement ratios illustrated in the first table on page 36 of the application.

b) Please provide a table showing the 2025/26 and 2026/27 percentage rate increases by class that would be required to have all customer classes achieve revenue to revenue requirement ratios of between 0.98 and 1.02 by 2026/27.

Response:

a) Please see the requested tables below:

2025-2026 Impacts

Revenue to Revenue Requirement (R/RR) Ratios Breakdown
2025-26 rate increase impact

Customer Class	Revenue Current Rates	Allocated Revenue Requirement	R/RR Ratio Current Rates	Revenue Revised Rates	Allocated Revenue Requirement	R/RR Ratio Revised Rates
	($ millions)	($ millions)		($ millions)	($ millions)	
Residential	$ 645.4	$ 657.2	0.98	$ 670.6	$ 685.0	0.98
Farms	193.5	202.4	0.96	201.0	211.7	0.95
Commercial	575.9	548.5	1.05	598.3	572.7	1.04
Power Class	912.0	899.7	1.01	947.6	928.8	1.02
Oilfields	476.4	490.6	0.97	495.0	510.1	0.97
Reseller	100.0	104.8	0.95	103.9	108.1	0.96
Total	**$ 2,903.2**	**$ 2,903.2**	**1.00**	**$ 3,016.4**	**$ 3,016.4**	**1.00**

2026-2027 Impacts

Revenue to Revenue Requirement (R/RR) Ratios Breakdown
2026-27 rate increase impact

Customer Class	Revenue Current Rates	Allocated Revenue Requirement	R/RR Ratio Current Rates	Revenue Revised Rates	Allocated Revenue Requirement	R/RR Ratio Revised Rates
	($ millions)	($ millions)		($ millions)	($ millions)	
Residential	$ 668.7	$ 674.3	0.99	$ 694.8	$ 703.4	0.99
Farms	205.1	211.8	0.97	213.1	221.3	0.96
Commercial	581.3	559.3	1.04	603.9	584.1	1.03
Power Class	1,008.2	1,000.5	1.01	1,047.5	1,033.0	1.01
Oilfields	515.5	527.6	0.98	535.6	548.4	0.98
Reseller	107.7	113.0	0.95	111.9	116.6	0.96
Total	**$ 3,086.5**	**$ 3,086.5**	**1.00**	**$ 3,206.8**	**$ 3,206.8**	**1.00**

b) Please see the requested tables below:

2025-2026 Impacts

Revenue to Revenue Requirement (R/RR) Ratios
2025-26 rate increase impact

Customer Class	R/RR Ratio Current Rates	2025-2026 Rate Increase	R/RR Ratio Revised Rates
Residential	0.98	3.3%	0.97
Farms	0.96	4.5%	0.96
Commercial	1.05	2.7%	1.03
Power Class	1.01	3.7%	1.02
Oilfields	0.97	5.7%	0.99
Reseller	0.95	6.1%	0.98
Total (System)	**1.00**	**3.9%**	**1.00**

2026-2027 Impacts

Revenue to Revenue Requirement (R/RR) Ratios
2026-27 rate increase impact

Customer Class	R/RR Ratio Current Rates	2026-2027 Rate Increase	R/RR Ratio Revised Rates
Residential	0.99	3.3%	0.98
Farms	0.97	4.5%	0.98
Commercial	1.04	2.7%	1.01
Power Class	1.01	3.7%	1.01
Oilfields	0.98	5.7%	1.01
Reseller	0.95	6.1%	1.00
Total (System)	**1.00**	**3.9%**	**1.00**

SRRP Q78 Reference: Proposed Rates

a) SaskPower states on page 33 and 34 of the 2026 Fiscal Test Embedded Cost of Service Results that "..due to the transition to a Conventional Rate Design and the number of years since SaskPower's last rate rebalancing rate application, to avoid rate shock to certain rate classes, more discretion in the ratios had to be taken in this application." Please explain what SaskPower means by a "Conventional Rate Design" – does this mean equal percentage increases to all rate components and customer classes?

b) Did SaskPower consider alternative rate designs for the current application? If so, please provide a summary of the alternatives considered.

c) Please discuss when SaskPower anticipates it will complete the phase-out of the Bary correction.

d) Please provide a schedule that compares, for each rate class:

   i. The 2026/27 class revenue requirement classified to each of energy, demand, and customer.

   ii. The forecast 2026/27 total class revenue generated by each of energy charges, demand charges, and customer charges.

e) For each customer class in each test year, please provide a table that compares the "ideal rates" calculated by the cost-of-service study for each of demand, energy, and customer with SaskPower's proposed energy, demand, and customer charges. Please comment on any material differences between proposed rates and ideal rates.

Response:

a) SaskPower defines "Conventional Rate Design" as electrical tariffs where each rate component reflects its corresponding costs without adjustment. Under Bary corrected rates, SaskPower's energy charges included a portion of demand-related costs, which resulted in overstated energy charges and understated demand charges. Following the recommendation of an independent consultant in 2020, SaskPower began phasing out the Bary Correction from its rates with the 2022 and 2023 rate applications.
b) SaskPower did not consider alternative rate designs for this application.
c) SaskPower anticipates it will complete the phase out of the Bary Correction over the next 3 to 5 applications.
d) (i) Please see the table below:

Class of Service	2026/27 - Revenue Requirement by Classification			
	Demand ($)	Energy ($)	Customer ($)	Total ($)
Residential	$ 302.9	$ 207.6	$ 193.0	$ 703.5
Farms	$ 104.2	$ 80.5	$ 36.6	$ 221.3
Commercial	$ 278.7	$ 234.7	$ 70.8	$ 584.1
Power Class	$ 368.1	$ 659.5	$ 5.4	$ 1,033.0
Oilfields	$ 246.6	$ 274.3	$ 27.5	$ 548.4
Reseller	$ 50.7	$ 65.7	$ 0.2	$ 116.6
Total	**$ 1,351.2**	**$ 1,522.2**	**$ 333.4**	**$ 3,206.8**

(ii) Please see the table below:

Class of Service	2026/27 - Revenue from Proposed Rates			
	Demand ($)	Energy ($)	Customer ($)	Total ($)
Residential	$ -	$ 529.2	$ 165.6	$ 694.8
Farms	$ 10.4	$ 167.3	$ 35.4	$ 213.1
Commercial	$ 117.7	$ 431.6	$ 54.7	$ 603.9
Power Class	$ 270.4	$ 765.8	$ 11.4	$ 1,047.5
Oilfields	$ 174.8	$ 339.5	$ 21.4	$ 535.6
Reseller	$ 47.6	$ 63.9	$ 0.4	$ 111.9
Total	**$ 620.7**	**$ 2,297.2**	**$ 288.9**	**$ 3,206.8**

e) Please see the "Q78(e).xls" Excel file for tables comparing the ideal and proposed rates for the FY2026 and FY2027 rate application. Ideal rates assume all customer classes are fully rebalanced to achieve an R/RR ratio of 0.98–1.01 each year, illustrating a fully rebalanced rate structure instead of using current ratios. Most differences between energy and demand targets result from shifting to a conventional rate design, which will be addressed during future rebalance or redesign efforts. The table below summarizes other key differences noticed between the proposed and ideal rates:

SaskPower
Powering our future®

2026 AND 2027 RATE APPLICATION
SRRP INTERROGATORIES

Customer Class	Comments
Farms	• E34 Basic Monthly Charge (BMC) must rise by 23%; other rate components remain within acceptable limits. • E41 Farm Irrigation BMC well below ideal level.
Commercial	• Proposed BMC for E07/E08/E10/E12 are high and will be addressed at the next rebalancing opportunity.
Streetlights	• S17 and S18 vary from their targets because it appears the LED conversion program's costs outweighed the energy and peak savings. With the program finished, we are monitoring future streetlight costs before adjusting rates.

SRRP Q79 Reference: Proposed Rates

a) Please provide a summary of municipal surcharges, including both the percentage of the surcharge and the total dollars collected for the most recent actual year available.

Response:

Municipal surcharge payments originated in the 1930s when municipally owned and privately owned electrical companies were a significant source of revenue to municipal councils. As the Saskatchewan Power Commission absorbed these small utilities, the rates to customers were reduced substantially but councils were afforded the option of requesting a surcharge to recover losses from profits, taxes and franchise fees previously paid by the small utilities. These agreements eventually became part of The Power Corporation Act as amended section 36.

Cities can request a municipal surcharge of up to 10%, and all participating cities have chosen 10%. Towns and villages can request a municipal surcharge of up to 5%, and all participating towns and villages have chosen 5%. Rural municipalities are not eligible for the municipal surcharge program.

The municipal surcharge is calculated as a percentage of the customer's total electrical charges before taxes. Total electrical charges include basic monthly charge, demand, consumption, and carbon charge. The municipal surcharge is not an expense to SaskPower; it is collected from customers and remitted to the municipal councils monthly.

Municipal surcharges			
(in millions)	Percentage	Number of Participating Municipalities	Actual Collected **2024-25**
Cities	10%	16	$ 71.7
Towns and villages	5%	372	13.6
TOTAL MUNICIPAL SURCHARGES		**388**	**$ 85.3**

SRRP Q80 Reference: System Operations

a) Please describe SaskPower's dispatch policies or rules for use of the various fuel sources to meet capacity and energy requirements. Please highlight any changes to these dispatch policies or rules since the last rate application.

b) Please discuss how the coal refurbishment program will affect SaskPower's system operation dispatch policies.

c) Does SaskPower anticipate the coal re-powering program will have any effect on the average generation efficiency of its natural gas generation facilities?

Response:

a) There are no changes to the dispatch policies or rules since the last rate application.

After meeting all transmission constraints, generation constraints, reserve and other ancillary service requirements, available units are dispatched in ascending order of incremental costs.

b) SaskPower's system operation dispatch policies remain unchanged – we will continue to follow the above stated policy when dispatching our units.

c) The impact of the coal re-powering program on the average generation efficiency of SaskPower's natural gas generation facilities could be influenced by many variables but in general should not have a material effect on it. Depending on power demand and renewable generation, it is possible that re-powered coal generation could offset some combined cycle gas generation and thus lower average efficiency of the natural gas fleet. However, having more coal generation available also reduces the capacity factors of the simple cycle natural gas peaking units which are less efficient units. As well, if market prices were favourable, this would create an export opportunity in which the combined cycle gas units would serve the export by ramping back up to their maximum levels.

SRRP Q81 Reference: Reliability

a) Please provide a table summarizing transmission SAIDI, transmission SAIFI, distribution SAIDI, distribution SAIFI, and distribution CAIDI for the most recent five years of actuals available for each of:

   i. SaskPower
   ii. SaskPower Targets
   iii. Canadian Utility Averages

b) Please discuss any factors contributing to SaskPower's performance relative to the average of the other utilities such as reporting framework (e.g., including or excluding Major Event Days, different requirements for planned outages, etc.).

c) Please discuss how SaskPower considers its reliability indicator performance when developing its capital plan. Does SaskPower prioritize capital spending to address particular areas or types of outages observed to impact reliability performance?

d) For each of transmission and distribution, please provide a breakdown of the causes of outages by type for both outage frequency and duration for each of the last three actual years available, similar to the format of the response to SRRP Q97 from the first round interrogatories in the 2022 and 2023 Rate Application review.

e) Please provide SaskPower's actual system average generation equivalent availability factor (EAF) for the most recent 5 actual years available and provide explanations for any changes over time.

f) NERC's Long Term Reliability Assessment (see: https://prod.nerc.com/globalassets/our%2Dwork/assessments/nerc_ltra_2025.pdf) indicated SaskPower had an elevated risk profile. Can you please outline what steps SaskPower has taken or will be taking to reduced this elevated risk profile.

Response:

a) The following table summarizes actual results for transmission SAIDI and SAIFI, and distribution SAIDI, SAIFI and CAIDI from 2020 through 2024 (calendar years), for both SaskPower and Canadian utility averages.

SAIDI, SAIFI and CAIDI

	Actual 2020	Actual 2021	Actual 2022	Actual 2023	Actual 2024
Transmission					
SAIDI (minutes)					
SaskPower (excluding MEDs)	141.7	131.7	134.7	126.5	129.6
SaskPower target (excluding MEDs)	140.0	140.0	135.0	135.0	135.0
SaskPower (including MEDs)	193.3	324.0	295.2	127.5	166.7
Canadian utilitiy average (CEA)*	109.6	137.1	153.0	190.7	124.8
SAIFI (interruptions)					
SaskPower (excluding MEDs)	3.1	2.2	2.1	2.5	2.5
SaskPower target (excluding MEDs)	3.1	3.1	3.0	3.0	3.0
SaskPower (including MEDs)	3.1	3.1	2.3	2.5	2.6
Canadian utilitiy average (CEA)*	1.4	1.4	1.5	1.9	1.4
Distribution					
SAIDI (hours)					
SaskPower (excluding MEDs)	6.1	5.8	5.2	5.2	5.0
SaskPower target (excluding MEDs)	5.9	5.9	5.9	5.9	5.5
SaskPower (including MEDs)	6.5	10.0	7.9	5.8	5.3
Canadian utilitiy average (excluding MEDs)*	4.8	4.6	5.1	5.6	4.9
SAIFI (interruptions)					
SaskPower (excluding MEDs)	2.8	3.4	3.7	3.9	3.5
SaskPower target (excluding MEDs)	2.4	2.4	2.7	2.9	3.7
SaskPower (including MEDs)	2.9	4.1	3.9	4.0	3.6
Canadian utilitiy average (excluding MEDs)*	2.2	2.3	2.4	2.8	2.4
CAIDI (interruptions)					
SaskPower (excluding MEDs)	2.1	1.7	1.4	1.3	1.4
SaskPower target (excluding MEDs)[2]	N/A	N/A	N/A	N/A	N/A
SaskPower (including MEDs)	2.2	2.4	2.0	1.5	1.5
Canadian utilitiy average (excluding MEDs)*	2.1	2.1	2.1	2.1	2.1

1. Electricity Canada's benchmarking data is provided in calendar years whearas SaskPower's annual targets, used for our Corporate Balanced Scorecard, are established for fiscal years.
2. SaskPower does not establish annual CAIDI targets

b) Consistent with the utility industry, SaskPower uses System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) to monitor reliability. These indices measure the duration and frequency, respectively, of outages on the system. SaskPower excludes Major Event Days (MEDs) when reporting reliability statistics both internally and externally, consistent with its industry. An MED is an outage event that is beyond what a utility's infrastructure is built to withstand. Severe storms and other unusual weather conditions can cause significant fluctuations in results and do not represent the performance of our system during regular operations.

With an average of nearly four customer accounts per circuit kilometre of distribution and transmission line, SaskPower has one of the lowest customer densities relative to grid infrastructure in the country. While this means that response time in rural areas is often longer due to repair location identification and travel time, it also means that the funding of capacity increases and ongoing maintenance can be challenging due to a smaller revenue base relative to the size of the grid.

SaskPower system delivery points are primarily fed from a single-circuit supply, meaning that the Corporation's transmission system is more prone to the effects of weather and equipment failures compared to other utility systems that are multi-circuit, or have more than one supply point. As such, transmission outages in our province can impact a greater number of customers and/or have longer durations in comparison to utilities with multi-circuit networked grids, which allow for immediate rerouting of transmission loads.

c) To provide its customers with a safe, continuous and adequate supply of electricity, SaskPower strives to enhance reliability while maximizing the in-service time of existing generation assets.

SaskPower prioritizes its capital expenditures based on a number of criteria and objectives, including: providing a reliable energy supply to meet forecasted load requirements; maintaining system reliability, ensuring security and power quality; and minimizing the cost of electricity for customers. SaskPower is committed to prioritizing energy security by diversifying our generation supply mix and expanding our transmission system.

SaskPower strives to keep pace with the performance of other utilities by implementing improved frameworks for making data driven, risk-based decisions that encourage continuous performance improvement and effective risk and cost management. In monitoring its reliability performance, SaskPower tracks major causes of both transmission and distribution outages and prioritizes capital accordingly.

Due to the characteristics of SaskPower's system, as assets age and more extreme weather effects of climate change become a reality, the performance challenges will increase compared to other utilities.

d) The following tables provide breakdowns for transmission and distribution of the causes of outages by type for both outage frequency and duration for the past three years.

Transmission outage causes

	2022-23		2023-24		2024-25	
Reason	**Duration (Minutes)**	**Interruptions***	**Duration (Minutes)**	**Interruptions***	**Duration (Minutes)**	**Interruptions***
Defective Equipment	15,669	93	14,554	112	31,474	153
Adverse Weather	23,789	424	4,381	308	9,363	354
Adverse Environment	387	12	4,716	20	3,327	44
System Condition	874	16	1,939	14	889	21
Human Element	6,103	71	2,020	70	659	10
Foreign Interference	606	36	10,841	133	1,479	43
System Configuration	747	26	3,144	41	1,230	42
Unknown	1,800	134	1,020	158	1,714	150
	49,975	**812**	**42,615**	**856**	**50,135**	**817**

	2022-23		2023-24		2024-25	
Reason	**Duration (Minutes)**	**Interruptions***	**Duration (Minutes)**	**Interruptions***	**Duration (Minutes)**	**Interruptions***
Defective Equipment	31.4%	11.5%	34.2%	13.1%	62.8%	18.7%
Adverse Weather	47.6%	52.2%	10.3%	36.0%	18.7%	43.3%
Adverse Environment	0.8%	1.5%	11.1%	2.3%	6.6%	5.4%
System Condition	1.7%	2.0%	4.6%	1.6%	1.8%	2.6%
Human Element	12.2%	8.7%	4.7%	8.2%	1.3%	1.2%
Foreign Interference	1.2%	4.4%	25.4%	15.5%	3.0%	5.3%
System Configuration	1.5%	3.2%	7.4%	4.8%	2.5%	5.1%
Unknown	3.6%	16.5%	2.4%	18.5%	3.4%	18.4%
	100%	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**

*Count of delivery point affected

Distribution outage causes

Reason	2022-23 Hours	2022-23 Interruptions	2023-24 Hours	2023-24 Interruptions	2024-25 Hours	2024-25 Interruptions
Unknown	199,660	155,836	171,815	160,840	142,375	127,252
Planned	396,878	198,628	513,068	229,238	457,783	195,939
Lightning	180,718	71,942	164,835	60,199	184,054	68,722
Icing	182,826	61,157	28,572	12,923	20,894	8,772
Other weather	208,297	82,052	195,879	63,840	180,602	75,194
Trees	236,349	86,174	122,278	61,730	153,983	67,549
Other vegetation	6,670	1,366	860	320	3,015	662
Birds / Animals	98,012	54,335	102,934	83,938	64,744	39,914
Accidents / internal (SPC)	342	287	869	6,101	7,614	7,877
Accidents / external	139,206	68,277	125,657	63,929	88,618	50,504
Vandalism	7,120	6,377	2,495	2,280	3,403	2,117
Loss of Transmission supply	837,830	1,001,458	922,712	1,195,826	836,363	903,776
Faulty equipment	355,565	207,074	365,135	204,346	374,389	177,746
Contamination	11,331	15,857	30,124	9,461	9,115	3,379
Overload	5,676	4,306	8,119	5,124	20,655	23,499
Cause code left blank	686	100	-	-	125,824	61,023
	2,867,166	**2,015,226**	**2,755,352**	**2,160,095**	**2,673,433**	**1,813,925**

Reason	2022-23 Duration	2022-23 Frequency	2023-24 Duration	2023-24 Frequency	2024-25 Duration	2024-25 Frequency
Unknown	7.0%	7.7%	6.2%	7.4%	5.3%	7.0%
Planned	13.9%	9.9%	18.6%	10.6%	17.1%	10.8%
Lightning	6.3%	3.5%	6.1%	2.8%	6.9%	3.8%
Icing	6.4%	3.0%	1.0%	0.6%	0.8%	0.5%
Other weather	7.3%	4.1%	7.1%	3.0%	6.8%	4.1%
Trees	8.2%	4.3%	4.4%	2.9%	5.8%	3.7%
Other vegetation	0.2%	0.1%	0.0%	0.0%	0.1%	0.0%
Birds / Animals	3.4%	2.7%	3.7%	3.9%	2.4%	2.2%
Accidents / internal (SPC)	0.0%	0.0%	0.0%	0.3%	0.3%	0.4%
Accidents / external	4.9%	3.4%	4.6%	3.0%	3.3%	2.8%
Vandalism	0.2%	0.3%	0.1%	0.1%	0.1%	0.1%
Loss of Transmission supply	29.2%	49.7%	33.5%	55.3%	31.3%	49.9%
Faulty equipment	12.4%	10.3%	13.3%	9.5%	14.0%	9.8%
Contamination	0.4%	0.8%	1.1%	0.4%	0.3%	0.2%
Overload	0.2%	0.2%	0.3%	0.2%	0.8%	1.3%
Cause code left blank	0.0%	0.0%	0.0%	0.0%	4.7%	3.4%
	100.0%	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**

e) The following table provides SaskPower's actual system average generation Equivalent Availability Factor (EAF) for the last five years.

Equivalent Availability Factor

	2020-21	2021-22	2022-23	2023-24	2024-25
Coal	78.2%	83.8%	80.1%	88.9%	81.3%
Gas	82.9%	78.7%	78.8%	82.7%	85.0%
Hydro	88.0%	87.3%	89.1%	89.0%	86.3%
Wind	97.3%	97.2%	96.5%	98.2%	98.3%
Total system average	**82.7%**	**83.1%**	**82.0%**	**86.9%**	**84.7%**

SaskPower's EAF performance remains fairly consistent and has experienced slight improvements in the past two years. An explanation of notable variances is included below:

- EAF performance in 2020-21 was impacted by the extension of a major overhaul on Boundary Dam Unit #6 (coal) and extension of the major overhaul on E.B. Campbell Hydroelectric Station Unit #3 (hydro).
- Generator failures at Queen Elizabeth Power Station contributed to slightly lower EAF for gas-fired power stations in 2021-22 and 2022-23.
- EAF performance for coal-fired power stations was slightly down in 2022-23 due to outages at Poplar River Unit #2 due to turbine damage and an extension of major overhaul.
- Coal EAF in 2024-25 was slightly lower due to the forced extension of a minor overhaul at Boundary Dam Unit #6.

f) This NERC Long Term Reliability Assessment (LTRA) report and rating for SaskPower was based on a SaskPower submission from July 2025. Since that time the provincial government, through The Saskatchewan First Energy Security Strategy and Supply Plan, extended the life of coal at the Boundary Dam Power Station.

SRRP Q82 Reference: Resource Planning

a) With reference to the response to the Panel's first recommendation from the 2022-2023 rate application where SaskPower states "SaskPower has completed extensive work on a public version of the Integrated Resource Plan. Over 60,000 people engaged with SaskPower through the process to date. SaskPower has updated the SRRP, and updates are publicly available on our website, saskpower.com. The release of the Long-term Supply Plan has been postponed due to the changing generation supply mix." Please:

   i. Provide a summary of the results of the public engagement on the Integrated Resource Plan.

   ii. Please provide an update on when SaskPower believes it will be in a position to provide a public version of the Long-term Supply Plan.

b) Please itemize the planning criteria used by SaskPower in developing its Resource Plans such as firm energy and capacity requirements. Please include any policy objectives such as reducing greenhouse gas emissions or installing a particular capacity of renewable generation.

c) Please discuss whether SaskPower has any current GHG emissions reductions targets. Please provide a chart that shows SaskPower's actual and forecast GHG emissions by year from 2005 through 2030.

d) Please provide a table that shows the contribution to SaskPower's GHG emissions by generation type for each year from 2005 through 2030.

e) Please provide an update to the response to SRRP first round Q102 from the 2022 and 2023 rate application for as many forecast years as SaskPower has available and can make public.

f) Please provide a table that compares the generation mix available to meet the winter peak and the generation mix available to meet the summer peak for planning purposes and describe the reasons for any differences in the seasonality of the planning capacity by generation type.

Response:

a)

i)

Summaries of each stage of the Future Supply Plan have been provided.

ii)

SaskPower is currently evaluating and implementing the Saskatchewan First Energy Security Strategy. A date where SaskPower believes it will be in a position to provide a public version of the Long-term Supply Plan is not known at this time.

The remainder of the response contains confidential information and cannot be released publicly. However a complete response has been provided to the Saskatchewan Rate Review Panel for their review.

SRRP Q83 Reference: Forecast Sales Revenue

a) Please provide a proof of revenue schedule for each of the test years showing:

i. The forecast billing determinants (e.g. number of customers, billed demand, energy), for each rate class;
ii. SaskPower's existing rates and proposed rates for each rate class
iii. Forecast revenues at existing rates and at proposed rates for each rate class.

Response:

a) Please note that a proof of revenue schedule is not provided for FY2026, as the energy and revenue figures for that year are derived from actual results to date combined with estimates based on the current budget variance, rather than the original FY2026 load forecast. This methodology was employed because the majority of the 2026 fiscal year had already passed at the time of the application's submission, making estimates more relevant. Consequently, billing determinants necessary for calculating a proof of revenue are not available. Complete billing determinants for the FY2027 application are available, and a corresponding proof of revenue schedule can be found in the attached Excel file ("Q83.xls").

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