1. Reference: General

a) During the September 15, 2021 presentation SaskEnergy noted that it plans to file an update to information included in the Application. Where applicable, please provide responses to the questions based on that updated Application.

The responses are based on the application as filed. As discussed with the Panel, an update will be filed on September 24, 2021 based on closing market prices as of September 23, 2021.

b) Please provide all schedules included in the application in MS excel format all formula intact.

The schedules have been provided in MS excel format, with the formulas intact. Because the schedules are produced from SaskEnergy's cost of gas model, which is propriety to SaskEnergy, the excel sheets contain external links.

2. Reference: Proposed Commodity Rate

a) Please discuss in further detail the rationale for proposing a commodity rate that covers the period from November 1, 2021 to October 31, 2023.

This allows SaskEnergy to maintain commodity price stability over a two-year period without drastically increasing the commodity rate after customers have experienced low commodity rates for the last couple of years. The two year rate period increases the commodity rate at a smaller increase than over a one year period mitigating rate shock for customers.

b) What would be the rate increases [rate $/volume and percentages] if the rates were adjusted effective November 1, 2021 and November 1, 2022, instead just one rate increase that covers two years.

i. Please provide the version of the table on page 1 of the Application and Schedule 3.0 to reflect November 1, 2021 and November 1, 2022 rate adjustment options based on costs for each year assuming GCVA balance still recovered over 24 months.

November 1, 2021	Commodity Rate Increase ($2.575/GJ to $3.20/GJ) $/Month	% Increase	Total Bill Impact % Increase
Residential	$6.13	28.0%	9.2%
Commercial Small	$30.00	28.0%	12.9%
Commercial Large	$391	28.0%	15.7%
Small Industrial	$1,620	28.0%	19.4%
Average		28.0%	10.8%

Schedule 3.0

SaskEnergy Incorporated

Determination of Commodity Rate for November 1, 2021 to October 31, 2022

Line	Description	Amount	Ref.
1	Half of Estimated Balance of GCVA at October 31, 2021 (000's)	$9,405,848	
2	November 2021 to October 2022 Gas Cost Forecast (000's)	$ 163,784,903	
3	Total Forecast Costs to Recover (000's)	$ 173,190,750	Line 1 plus Line 2
4	November 2021 to October 2022 Forecast Sales (GJs - 000's)	54,099,913	
5	November 2021 to October 2022 Monthly Weighted Cost per Unit of Sales	**$3.201**	Line 3 divided by Line 4
6	Proposed Commodity Rate	**$3.20**	
7	Customer Commodity Rate Equivalent (Heating Value = 39.90 MJ/m^3)	**12.77**	cents per cubic metre
8	Estimated Balance of GCVA at October 31, 2022	$9,508,645	

Notes:

1. Numbers might not add precisely due to rounding.

2. SaskEnergy purchases natural gas on an energy basis (GJs) and bills its customers on a volume basis (cubic metres). The Heating Value used to convert energy to volume is a forecast based on the previous average volume-weighted twelve months.

3. The methodology is designed to target a zero GCVA balance at the end of the one year period (November 2021 - October 2022).

November 1, 2022	Commodity Rate Decrease ($3.20/GJ to $3.07/GJ) $/Month	% Decrease	Total Bill Impact % Decrease
Residential	($1.12)	(4.0%)	(1.5%)
Commercial Small	($5.48)	(4.0%)	(2.1%)
Commercial Large	($72)	(4.0%)	(2.5%)
Small Industrial	$(296)	(4.0%)	(3.0%)
Average		(4.0%)	(1.8%)

Schedule 3.0

SaskEnergy Incorporated

Determination of Commodity Rate for November 1, 2022 to October 31, 2023

Line	Description	Amount	Ref.
1	Estimated Balance of GCVA at October 31, 2022 (000's)	$9,508,645	
2	November 2022 to October 2023 Gas Cost Forecast (000's)	$ 156,093,978	
3	Total Forecast Costs to Recover (000's)	$ 165,602,623	Line 1 plus Line 2
4	November 2022 to October 2023 Forecast Sales (GJs - 000's)	53,880,685	
5	November 2022 to October 2023 Monthly Weighted Cost per Unit of Sales	**$3.074**	Line 3 divided by Line 4
6	Indicative Commodity Rate	**$3.07**	
7	Customer Commodity Rate Equivalent (Heating Value = 39.90 MJ/m^3)	**12.26**	cents per cubic metre

Notes:

1. Numbers might not add precisely due to rounding.

2. SaskEnergy purchases natural gas on an energy basis (GJs) and bills its customers on a volume basis (cubic metres). The Heating Value used to convert energy to volume is a forecast based on the previous average volume-weighted twelve months.

3. The methodology is designed to target a zero GCVA balance at the end of the one year period (November 2022 - October 2023).

ii. Please provide a version of the table on page 1 of the Application and Schedule 3.0 that reflects November 1, 2021 and November 1, 2022 rate adjustment options based on costs for each year but assuming GCVA balance is recovered over 12 months.

November 1, 2021	Commodity Rate Increase ($2.575/GJ to $3.38/GJ) $/Month	% Increase	Total Bill Impact % Increase
Residential	$7.67	35.0%	11.5%
Commercial Small	$37.53	35.0%	16.1%
Commercial Large	$490	35.0%	19.6%
Small Industrial	$2,026	35.0%	24.2%
Average		35.0%	13.5%

Schedule 3.0

SaskEnergy Incorporated

Determination of Commodity Rate for November 1, 2021 to October 31, 2022

Line	Description	Amount	Ref.
1	Estimated Balance of GCVA at October 31, 2021 (000's)	$18,811,695	Schedule 2.0: (P3, Col. 12, Line 20)
2	November 2021 to October 2022 Gas Cost Forecast (000's)	$ 163,784,903	Schedule 1.0: (P1, Col. 13, Line 12) + (P2, Col. 13, Line 12)
3	Total Forecast Costs to Recover (000's)	$ 182,596,598	Line 1 plus Line 2
4	November 2021 to October 2022 Forecast Sales (GJs - 000's)	54,099,913	Schedule 1.0: (P1, Col. 13, Line 13) + (P2, Col. 13, Line 13)
5	November 2021 to October 2022 Monthly Weighted Cost per Unit of Sales	**$3.375**	Line 3 divided by Line 4
6	Indicative Commodity Rate	**$3.38**	
7	Customer Commodity Rate Equivalent (Heating Value = 39.90 MJ/m^3)	**13.47**	cents per cubic metre

Notes:

1. Numbers might not add precisely due to rounding.

2. SaskEnergy purchases natural gas on an energy basis (GJs) and bills its customers on a volume basis (cubic metres). The Heating Value used to convert energy to volume is a forecast based on the previous average volume-weighted twelve months.

3. The methodology is designed to target a zero GCVA balance at the end of the one year period (November 2021 - October 2022).

November 1, 2022	Commodity Rate Decrease ($3.38/GJ to $2.89/GJ) $/Month	% Decrease	Total Bill Impact % Decrease
Residential	($4.27)	(14.4%)	(5.7%)
Commercial Small	($20.86)	(14.4%)	(7.7%)
Commercial Large	($272)	(14.4%)	(9.1%)
Small Industrial	($1,126)	(14.4%)	(10.8%)
Average		(14.0%)	(6.6%)

Schedule 3.0

SaskEnergy Incorporated

**Determination of Commodity Rate for
November 1, 2022 to October 31, 2023**

Line	Description	Amount	Ref.
1	Estimated Balance of GCVA at October 31, 2021 (000's)	($249,829)	Schedule 2.0: (P3, Col. 12, Line 20)
2	November 2021 to October 2023 Gas Cost Forecast (000's)	$ 156,093,978	Schedule 1.0: (P1, Col. 13, Line 12)
3	Total Forecast Costs to Recover (000's)	$ 155,844,149	Line 1 plus Line 2
4	November 2021 to October 2023 Forecast Sales (GJs - 000's)	53,880,685	Schedule 1.0: (P1, Col. 13, Line 13)
5	November 2021 to October 2023 Monthly Weighted Cost per Unit of Sales	**$2.892**	Line 3 divided by Line 4
6	Indicative Commodity Rate	**$2.89**	
7	Customer Commodity Rate Equivalent (Heating Value = 39.90 MJ/m^3)	**11.54**	cents per cubic metre

Notes:

1. Numbers might not add precisely due to rounding.

2. SaskEnergy purchases natural gas on an energy basis (GJs) and bills its customers on a volume basis (cubic metres). The Heating Value used to convert energy to volume is a forecast based on the previous average volume-weighted twelve months.

3. The methodology is designed to target a zero GCVA balance at the end of the one year period (November 2022 - October 2023).

c) Please provide the impact of each cost increase in 2021/22 and 2022/23 compared to 2018 out of total rate increase of 25.8% [e.g., impact of clearing GCVA balance is about 7% of 25.8% total rate increase, increase in cost of purchases, increase in O&M, etc.].

Following are the components of the commodity rate and an estimate of the cost on a per gigajoule basis. Items such as purchases going into storage and being sold in a different gas year complicates translating the costs to commodity rate components.

	2021	2018	Difference
Raw cost of purchased gas including hedges	$ 2.33	$ 2.41	$ (0.08)
Impact of change in Storage Gas cost	$ 0.06	$ (0.10)	$ 0.16
Transportation	$ 0.50	$ 0.45	$ 0.05
OM&A	$ 0.03	$ 0.03	$ -
Forecast Cost of Gas	$ 2.92	$ 2.79	$ 0.13
GCVA	$ 0.17	$ (0.22)	$ 0.39
Change in Revenue due to HV	$ 0.06		$ 0.06
Proposed Commodity Rate	$ 3.15	$ 2.57	$ 0.58

d) Please discuss if more frequent commodity price changes may reduce the impact to customers from rate adjustments and also avoid material accumulation of funds in the GCVA.

SaskEnergy believes that more frequent commodity rate changes are not necessary. SaskEnergy's commodity risk management strategy adds the stability to its commodity rate that the majority of customers indicate they desire. Regarding the GCVA, when natural gas prices change rapidly, more frequent rate changes may or may not reduce the impact to the GCVA. For example, with the rise in natural gas prices this past summer, Winnipeg increased their commodity rate 27% this past quarter and Vancouver increased their commodity rate 24%.

e) Please provide the basis for the assumed heating value of 39.90 MJ/m^3 in this Application.

SaskEnergy updates its heat value forecast on an annual basis. It reviews the actual heat values from the previous year as well as the heat values from Alberta interconnects to establish the forecast. This review includes upcoming changes to the system that may impact the heat value.

f) Prior reviews have noted that variations in heat value result in some customers paying more than others to achieve the same heating energy, depending on geographic location. Please discuss if this is still the case.

Yes, this is still the case. SaskEnergy has begun a heat value business case to assess the options on how best to resolve the heat value variations.

g) Please provide heating value by region and the impact to customer bills in each region if the commodity rates are approved based on 39.90 MJ/m^3.

	Average Residential Bill by Heat Value									
Residential	Regina	Moose Jaw	Weyburn	Estevan	Swift Current	Yorkton	Melville	Saskatoon	Prince Albert	North Battleford
Commodity at HV 39.90 MJ/m³	$ 325	$ 354	$ 314	$ 319	$ 356	$ 327	$ 344	$ 354	$ 340	$ 354
Actual Commodity at City HV	$ 341	$ 341	$ 341	$ 341	$ 341	$ 341	$ 341	$ 341	$ 341	$ 341
Commodity Bill Variance ($)	$ (16)	$ 12	$ (27)	$ (22)	$ 15	$ (14)	$ 3	$ 13	$ (1)	$ 13
Commodity Bill Variance (%)	-5%	4%	-8%	-6%	4%	-4%	1%	4%	0%	4%

	Average Commercial Small Bill by Heat Value									
Commercial Small	Regina	Moose Jaw	Weyburn	Estevan	Swift Current	Yorkton	Melville	Saskatoon	Prince Albert	North Battleford
Commodity at HV 39.90 MJ/m³	1,578	1,716	1,525	1,550	1,728	1,588	1,668	1,720	1,651	1,718
Actual Commodity at City HV	1,655	1,655	1,656	1,655	1,656	1,656	1,655	1,656	1,655	1,655
Commodity Bill Variance ($)	$ (77)	$ 60	$ (130)	$ (105)	$ 72	$ (68)	$ 13	$ 64	$ (5)	$ 63
Commodity Bill Variance (%)	-5%	4%	-8%	-6%	4%	-4%	1%	4%	0%	4%

	Average Commercial Large Bill by Heat Value									
Commercial Large	Regina	Moose Jaw	Weyburn	Estevan	Swift Current	Yorkton	Melville	Saskatoon	Prince Albert	North Battleford
Commodity at HV 39.90 MJ/m³	19,303	20,987	18,659	18,961	21,131	19,422	20,402	21,039	20,189	21,011
Actual Commodity at City HV	20,248	20,249	20,251	20,250	20,250	20,250	20,248	20,251	20,249	20,246
Commodity Bill Variance ($)	$ (944)	$ 738	$ (1,592)	$ (1,289)	$ 881	$ (828)	$ 154	$ 787	$ (60)	$ 765
Commodity Bill Variance (%)	-5%	4%	-8%	-6%	4%	-4%	1%	4%	0%	4%

Heat Value Area	Regina	Moose Jaw	Weyburn	Estevan	Swift Current	Yorkton	Melville	Saskatoon	Prince Albert	North Battleford
Weighted Average HV (MJ/m³)	41.79	38.44	43.24	42.55	38.18	41.54	39.54	38.35	39.96	38.39

* Based on 2020-21 Actual Heat Value (April - March)

h) With regard to the jurisdictions included in the competitiveness comparison in Tab 6:

i. Please provide details regarding the frequency of commodity rate adjustments in these jurisdictions and how this compares to SaskEnergy.

City	Frequency of Rate Changes
Vancouver	quarterly
Edmonton	monthly
Calgary	monthly
Winnipeg	quarterly
Hamilton	quarterly
Toronto	quarterly
Montreal	monthly

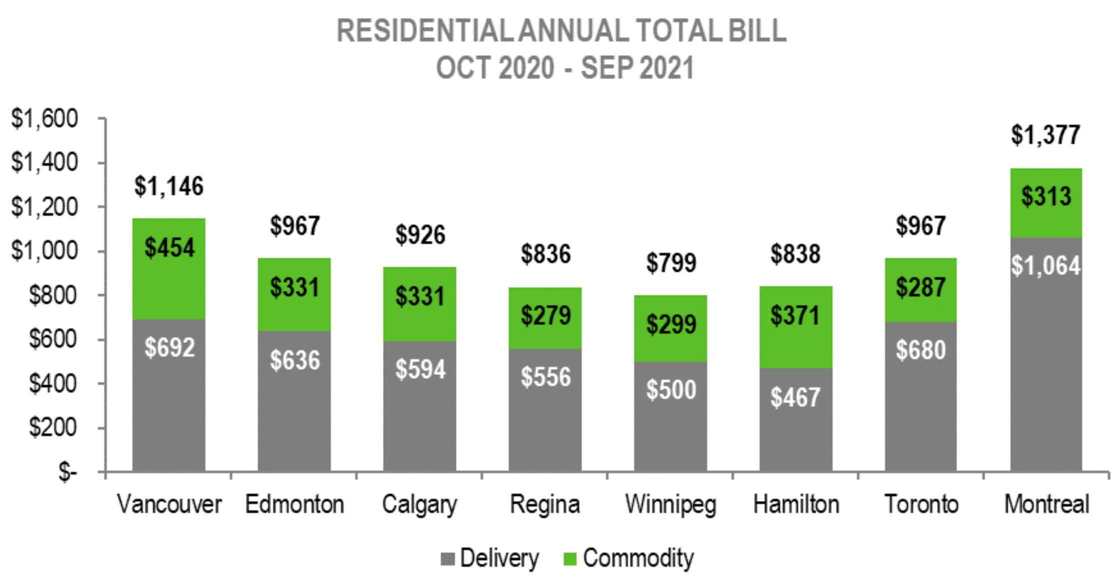
In addition to monitoring the GCVA, SaskEnergy officially reviews its commodity rate twice per year, in the spring and fall, for either an April 1 or November 1 rate change. If the forecasted natural gas costs are substantially different from the forecasted commodity revenue, then a recommendation to proceed with a commodity rate application will be initiated.

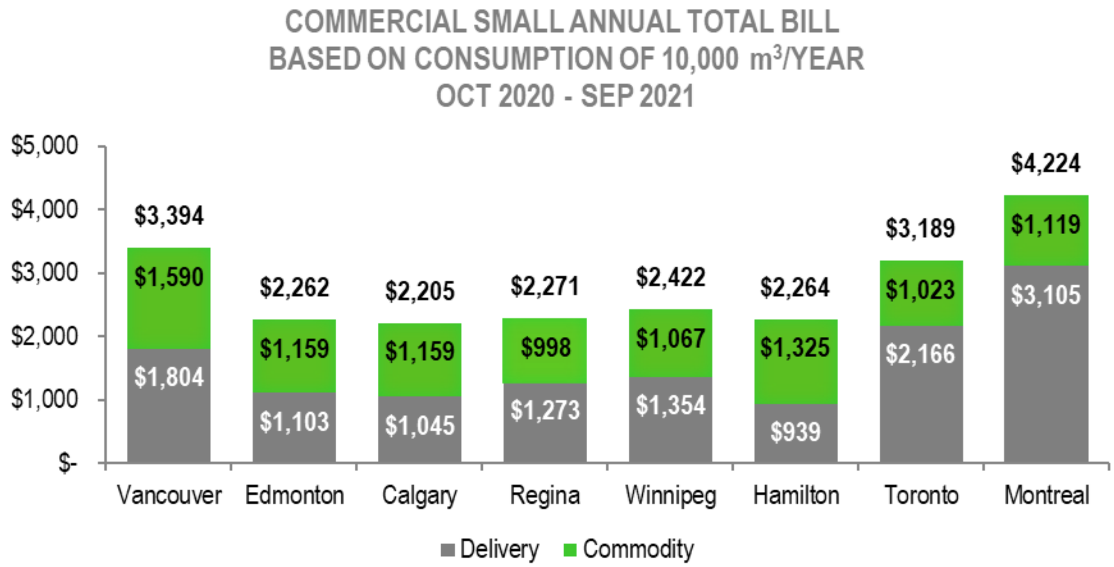
ii. Please discuss any key differences in commodity rate design, cost base and/ or approach compared to SaskEnergy.

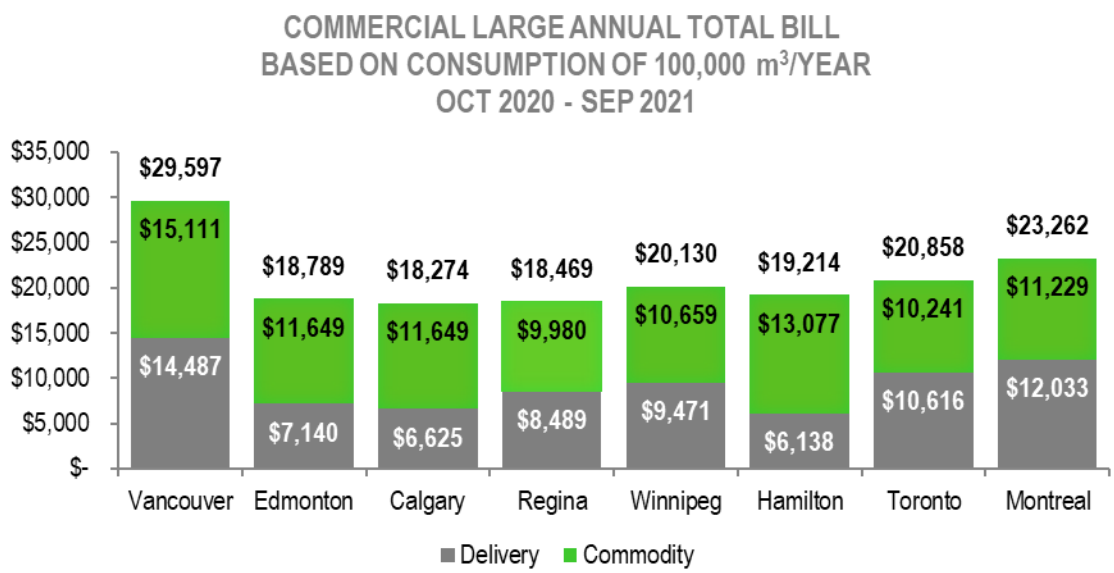
The components that make up the cost of gas are essentially the same across utilities. However, unlike SaskEnergy, most major Canadian utilities no longer hedge so natural gas purchases are transacted at current market prices.

With respect to rate design, with the exception of the Alberta utilities, the other utilities use a 12 month test period, which includes the forward market prices for the next twelve months. Alberta uses only a one-month test period. Alberta's rate design also aims to collect and refund GCVA GCVA balances over one month. The remaining utilities, including in Montreal where the commodity rate is reset monthly, refund and collect the GCVA over a 12 month test period.

iii. Please provide annual bill comparison for SaskEnergy and all other jurisdictions noted in Tab 6 for residential, commercial and industrial users that include both delivery and commodity portion of bills. Please show delivery and commodity portions of the bills separately in comparison.







i) On page 1 of the Application SaskEnergy notes that "natural gas prices have been rising over the past year and have essentially doubled since SaskEnergy last adjusted its commodity rate."

On page 7 of the Application, SaskEnergy notes that "the GCVA as at October 31, 2021 is projected to have a balance of $18.8 million owing from customers to SaskEnergy. The forecasted GCVA balance owing is a result of an increased cost of gas, relative to commodity sales revenue."

Schedule 2.0 of the Application shows that GCVA balance forecast to change from

$18.841 million owing to customer in April 2019 [last time the commodity rate was changed] to $18.812 million owing from customers in October 2021 (subject to any updates provided), or net change of $37.653 million in GCVA.

i. Please discuss the effects of the change in GCVA between April 2019 to October 2021 have on intergenerational fairness/equity?

Because SaskEnergy has a fairly stable customer base, the same customers that caused the GCVA balance are essentially the same customers from whom the GCVA is recovered or refunded. SaskEnergy estimates the intergenerational fairness would impact less than 1% of the customers.

ii. Please discuss why SaskEnergy did not propose rate adjustments earlier than November 1, 2021 considering increasing cost of gas relative to commodity sales revenues. What impact did COVID-19 have?

SaskEnergy reviews their rates on a semi-annual basis. When the rates were reviewed in late 2020, which would result in an April 1, 2021 rate change, a rate increase was not required. Upon review this summer, SaskEnergy determined that a rate increase for November 2021 was necessary.

There appears to be no correlation between COVID-19 and natural gas prices.

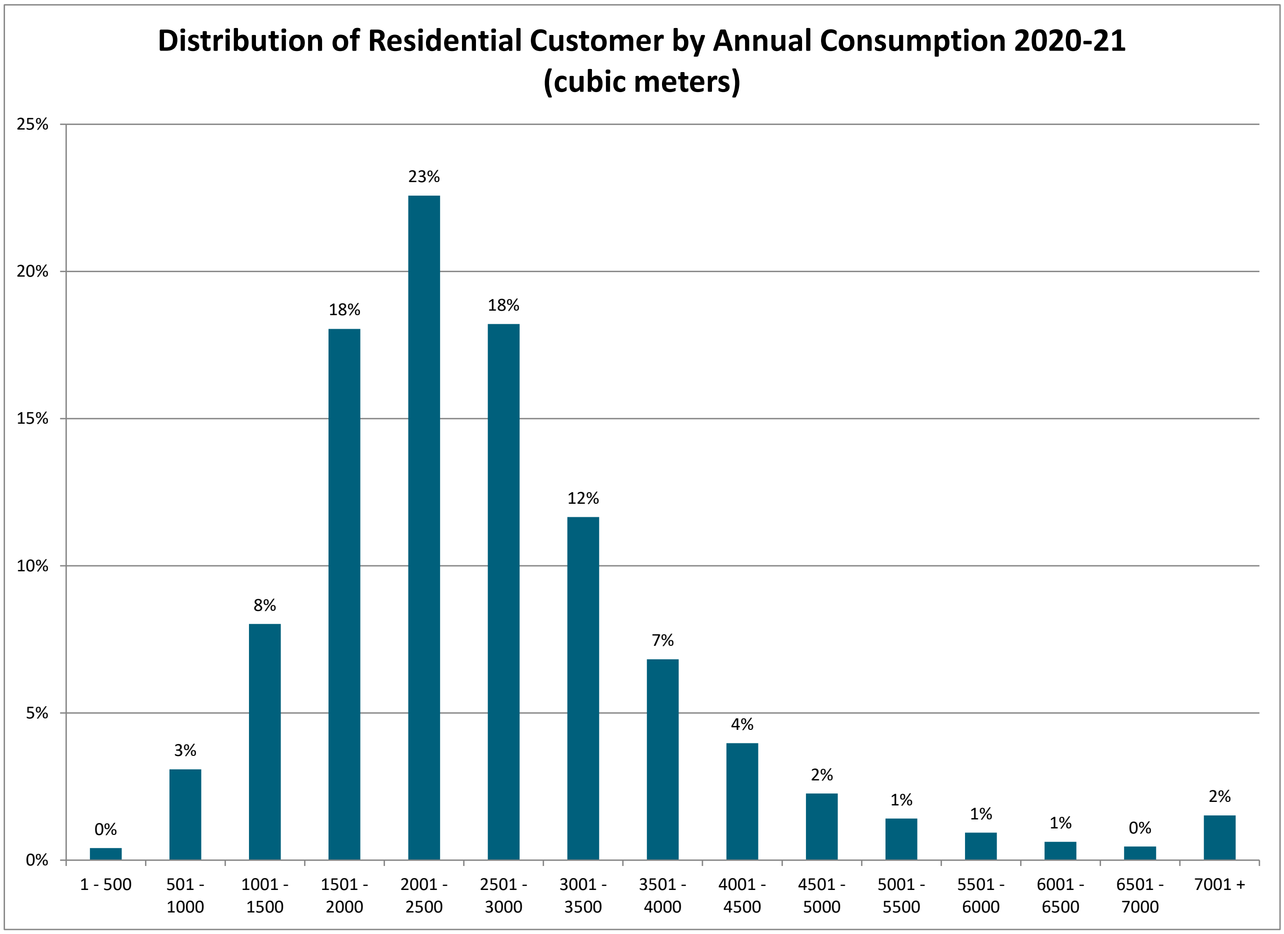
iii. Describe the impact the GCVA balance has on "rate stability" considering bill impacts from GCVA in the current proposed rate adjustments effective November 1, 2021?

The GCVA can act as a buffer against the need for frequent rate changes. In this rate application, collecting the GCVA is adding to the commodity rate required more than the forecast cost of gas sold.

Refer to question 2 (c).

3. Customer Bill impacts

a) To better understand the distribution of potential customer bill impacts, please provide a frequency distribution chart showing the percentage of residential customers at annual consumption intervals of 0-500 cubic meters, 501-1000 cubic meters, etc. at 500 cubic meter intervals up to 7001 or greater cubic meters.



b) What is SaskEnergy's understanding of the impact of the proposed rate to commercial/ small industrial customers? Has SaskEnergy communicated with these customers groups on potential impacts from the proposed rate increase?

SaskEnergy understands that a commodity rate increase has a larger impact on customers that use more natural gas. SaskEnergy has not communicated to these groups separately. SaskEnergy provides the same communication to all customer groups.

4. Reference: Forecast Cost of Gas Sold

a) On page 2 of the Application SaskEnergy notes that "SaskEnergy does not incur a profit or loss on the sale of the commodity." Please confirm that this is true for SaskEnergy as a whole, i.e., including all SaskEnergy subsidiaries. If not confirmed, please explain.

TransGas, a wholly owned subsidiary of SaskEnergy, provides receipt transportation from Alberta to the TransGas Energy Pool (TEP) in Saskatchewan. This service is comprised of two components: Alberta and Saskatchewan transport. The NGTL toll on the Alberta side is a flow through with no margin or profit to TransGas. However on the Saskatchewan side, where TransGas provides the service, they earn a return on their investment in infrastructure.

b) On page 3 of the Application SaskEnergy notes that "as SaskEnergy is now purchasing a larger proportion of natural gas from Alberta, the cost of transportation has a larger impact on the commodity rate." Please provide transportation cost per GJ for the last five years and explain the reasons for each change.

The following table shows the actual transportation costs as a portion of the commodity rate, based on actual commodity sales. Therefore, when more volume flows due to colder than normal weather, the transportation cost per gigajoule will be impacted.

Fiscal	Transportation Cost per GJ in commodity rate	Rationale
2016-17	$0.37	N/A
2017-18	$0.30	Contract volume increase
2018-19	$0.39	Contract volume increase and rate increase
2019-20	$0.46	Contract volume increase
2020-21	$0.50	Contract volume increase and rate increase

c) Please clarify if the transportation costs for the period from November 1, 2021 through October 31, 2023 include any increases in TransGas contract rates for firm transportation service. If yes, please provide details of assumed increases and rationale for the rate changes.

The transportation costs do not include increases for TransGas transportation service rates.

d) The schedules show that transportation costs vary from summer to winter while the daily delivery volumes remain the same throughout the year. Please explain why the costs vary by month and provide details of calculation of transportation costs for each month showing volumes and rates used to arrive at “cost upstream of TEP” amounts in Schedule 1.0 and “Receipt Transport” $/GJ shown in Schedule1.1.
Please provide these calculations in MS excel format with all formulae intact.

SaskEnergy is required to contract for all firm transportation on a yearly basis therefore the costs will be relatively the same each month regardless of flows and only vary based on the number of days in the month. Calculations are in the table below.

	Rate per GJ	Volume per Day	Total Volume	Total Cost
January	$0.3845	200000	6200000	$2,383,900.00
February	$0.3845	200000	5600000	$2,153,200.00
March	$0.3845	200000	6200000	$2,383,900.00
April	$0.3845	200000	6000000	$2,307,000.00
May	$0.3845	200000	6200000	$2,383,900.00
June	$0.3845	200000	6000000	$2,307,000.00
July	$0.3845	200000	6200000	$2,383,900.00
August	$0.3845	200000	6200000	$2,383,900.00
September	$0.3845	200000	6000000	$2,307,000.00
October	$0.3845	200000	6200000	$2,383,900.00
November	$0.3845	200000	6000000	$2,307,000.00
December	$0.3845	200000	6200000	$2,383,900.00

e) On page 9 of the Application SaskEnergy notes that “after experiencing colder than normal weather across much of North America this past winter (i.e. extreme cold in Texas), summer began with a heat dome covering much of the continent that brought drought conditions and increased gas-fired power generation.”

SaskEnergy also notes that “in Alberta, the heat dome caused natural gas production to be reduced. During extreme heat, the volume of natural gas that mid-stream facilities can process is greatly reduced. Unplanned outages at compressor stations also resulted in curtailments which caused additional price volatility."

i. How do seasonal variations in demand in Canada compare to the rest of North America?

Generally speaking, demand for natural gas to meet heating load in the winter is much higher in the northern climates, including Canada. On the other hand, demand for natural gas to generate electricity to meet air conditioning load during the summer period is much higher in the south/central part of North America and extends into Canada at varying degrees.

ii. How do these seasonal variations in demand and supply impact SaskEnergy purchases [both volumes and prices]?

As indicated on Page 10 and 11 of the Application, SaskEnergy purchases approximately the same volume of natural gas each day of the year. In the summer, when customer requirements are less than purchases, the excess natural gas is injected into storage. Then in the winter, when customer requirements exceed purchases, gas is withdrawn from storage. Therefore the seasonal variations in demand do not impact SaskEnergy significantly. With respect to prices, many factors can influence a change in price.

iii. How the above do noted production reductions impact SaskEnergy purchases [both volumes and prices] considering SaskEnergy hedges most of the gas purchase as shown on page 4 of the Application?

The production reductions had an on impact on the spot and near term price of natural gas in Alberta this summer. SaskEnergy had approximately 50% of this summer's gas purchase hedged, so it only had exposure to higher prices on half of the gas purchased. The higher prices are reflected in the price of gas in storage for sale this upcoming winter; as well as in the growth in the GCVA this past summer.

f) The figure on page 9 of the Application [AECO Monthly Index Historical Prices] shows the average price from 2015 to present was $2.08/GJ. Please provide the average cost of purchases [excluding transportation cost and losses] for SaskEnergy for the same period, separately showing Alberta and Saskatchewan purchases.

The average cost of gas purchases for SaskEnergy before any other costs is outlined in the table below:

Year	Average Cost
2015	$4.07
2016	$3.78
2017	$3.09
2018	$2.57
2019	$2.28
2020	$2.40

g) Slide #7 of SaskEnergy's September 15, 2021 presentation shows that by 2027 the production of gas is expected to increase, including a significant increase in the Appalachia region. How will these increases in production impact forward prices?

It is difficult to predict, as so many other factors impact price. It could translate to lower prices, because of more domestic supply; or it could translate to higher prices, because more supply is available for the global market.

h) Please provide details regarding how Saskatchewan Purchases, Alberta Purchases, Price Risk Management (inflows)/Outflows, and Costs upstream of TEP in Schedule 1 are calculated for the period from November 2021 to October 2023 showing volumes, applicable rates and other adjustments, if any, used to arrive each cost item. Please provide calculations in MS excel format.

The schedules are produced from SaskEnergy's proprietary Cost of Gas model.

Saskatchewan purchases are derived by taking the total cost of gas before hedges and subtracting the total cost of Alberta purchases to determine the value of the gas purchased in Saskatchewan.

Alberta purchases are derived by taking the total cost of fixed price and index gas purchased in Alberta.

The Price Risk Management inflows/outflows is derived by taking the profits/losses on the natural gas swaps.

Costs upstream of TEP are calculated by taking the firm transportation volume from Alberta and multiplying it by the rate. Please refer to 4(d) for this calculation.

i) Please provide details of the following:

i. How are Cost of Purchase Gas in Schedule 1.1 [$3.011/GJ, $2.544/GJ, $2.632/GJ, $2.351/GJ] derived? Please provide a version of Schedule 1.1 that itemizes the add-ons, premiums or adjustments between the AECO forward price and the Cost of Purchase Gas before financial hedges.

These are the total costs of gas divided by total volume of gas purchased (fixed price and floating). The model is currently not set up to provide this data and would required a revision to include an itemized Schedule as requested.

ii. How does the Cost of Purchase Gas in Schedule 1.1 [$3.011/GJ, $2.544/GJ, $2.632/GJ, $2.351/GJ] reconcile to $2.20/GJ "for the next two years" on slide #16 in the SaskEnergy September 15, 2021 presentation?

The Cost of Gas Purchased in Schedule 1.1 references the cost of all gas purchases (including fixed price and floating purchases) whereas slide 16 of the presentation refers to only the fixed priced AECO hedges.

iii. Please provide details on how "change in price due to Financial Hedges" in Schedule 1.1. are derived [-$0.745/GJ and -$0.447/GJ].

This is the average cost per GJ of gas purchases before hedges minus the average cost of gas per GJ of the fixed price hedges gives this difference.

	Average Cost of Purchase Gas before Hedges	Average Cost of Purchase Gas after Hedges	Difference
2021-22	$3.011	$2.266	$0.745
2022-23	$2.632	$2.185	$0.447

iv. Please explain why there is a difference between "change in price due to Financial Hedges" for Nov 2021-March 2022 compared to Nov 2022 – March 2023. Please provide underlining assumptions.

The difference is due to

1) Different forecasted purchase volumes based on load forecast

2) The forward price of natural gas is different in each period.

3) The hedged price is different in each period.

v. Please explain why there is no “change in price due to Financial Hedges” for summer deliveries considering SaskEnergy hedges summer purchases.

SaskEnergy has no financial hedges for the summer periods therefore there is no change in price to account for during the summer.

j) Please clarify the source for “forward price at August 3, 2021” in figure on page 9 of the Application. Please compare the AECO Forward Prices used in Schedule 1.1 with the most recently available AECO Forward Prices. Please indicate the approximate impact on the proposed commodity rate of updating the most recently available AECO Forward Prices, if applicable.

The source for the forward price at August 3, 2021 on page 9 of the Application is the ICE NGX forward curve.

The AECO forward prices in Schedule 1.1 were sourced from the August 3, 2021 TD Energy Daily market pricing. A comparison to the rates as of September 14, 2021 (as provided at the September 15th presentation) are as follows:

AECO Forward Prices

	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22
Rate Application - August 3, 2021	4.09	4.09	4.09	4.09	4.09	2.96	2.96	2.96	2.96	2.96	2.96	2.96
AECO Forward Price - September 14, 2021	4.87	4.87	4.87	4.87	4.87	3.50	3.50	3.50	3.50	3.50	3.50	3.50

	Nov-22	Dec-22	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23
Rate Application - August 3, 2021	3.24	3.24	3.24	3.24	3.24	2.50	2.50	2.50	2.50	2.50	2.50	2.50
AECO Forward Price - September 14, 2021	3.86	3.86	3.86	3.86	3.86	2.75	2.75	2.75	2.75	2.75	2.75	2.75

The impact on the proposed commodity rate required would be a higher commodity rate of $3.24/GJ ($0.1294/m3).

k) On page 10 of 2018 Commodity and Delivery Service Rate Application SaskEnergy stated that AECO prices are “depressed in both the near-term and the longer-term, as it will take several years for pipelines to be constructed to increase export capacity. Since Saskatchewan is downstream of the pipeline capacity restriction at the Alberta/Saskatchewan border, natural gas prices in Saskatchewan have not participated in the price decreases experienced in Alberta.” Does the condition noted in the 2018 application still exist today? If not, please explain how the issue was resolved and any impacts on purchase costs and volumes.

The condition of pipeline capacity restrictions does not still exist. The situation was resolved through new facilities being built and going in service. However, it is worth noting that there is not yet excess firm capacity available in Alberta.

l) On page 10 of 2018 Commodity and Delivery Service Rate Application SaskEnergy noted that "[n]atural gas in Saskatchewan has been trading in excess of AECO plus $1.00/GJ in recent months, which is significantly higher than the typical differential of about $0.15 to $0.20/GJ in recent years. This strong pricing differential is expected to continue into the 2018-19 gas-year, with one-year gas contracts in Saskatchewan expected to trade in the AECO plus $0.50 to $0.75/GJ range." In the current Application, page 13, SaskEnergy notes that "within this application SaskEnergy is forecasting this TEP/AECO basis to be approximately $0.25/GJ for gas purchased in Saskatchewan."

i. Please provide the month-to-month price differential for the last five years. Please explain any significant month-to-month changes.

Although there is typically a relationship between the shorter-term and the one-year pricing, it is important to recognize that these are two very distinct and separate terms, and given the lack of liquidity of gas that trades in Saskatchewan, short-term and one-year pricing can be very different.

Month	TEP Basis	Month	TEP Basis	Month	TEP Basis	Month	TEP Basis	Month	TEP Basis
Jan-17	$0.10	Jan-18	$3.24	Jan-19	$0.18	Jan-20	$0.01	Jan-21	$0.01
Feb-17	$0.06	Feb-18	$0.87	Feb-19	$0.02	Feb-20	$0.00	Feb-21	$0.01
Mar-17	$0.05	Mar-18	$0.31	Mar-19	$0.24	Mar-20	-$0.02	Mar-21	$0.00
Apr-17	$0.05	Apr-18	$0.83	Apr-19	$0.90	Apr-20	$0.00	Apr-21	$0.00
May-17	$0.08	May-18	$0.87	May-19	$0.19	May-20	$0.00	May-21	$0.00
Jun-17	$0.14	Jun-18	$1.42	Jun-19	$0.80	Jun-20	$0.00	Jun-21	-$0.01
Jul-17	$0.63	Jul-18	$1.05	Jul-19	$0.35	Jul-20	-$0.03	Jul-21	$0.02
Aug-17	$0.37	Aug-18	$1.84	Aug-19	$0.42	Aug-20	-$0.02	Aug-21	$0.51
Sep-17	$0.91	Sep-18	$1.58	Sep-19	$1.13	Sep-20	$0.02	Sep-21	$0.31
Oct-17	$1.28	Oct-18	$2.12	Oct-19	$0.11	Oct-20	$0.01		
Nov-17	$1.10	Nov-18	$2.60	Nov-19	-$0.01	Nov-20	$0.01		
Dec-17	$1.56	Dec-18	$2.41	Dec-19	$0.00	Dec-20	$0.01		

ii. Is it SaskEnergy's expectation that the price differential is back to a "typical differential" noted in the 2018 application?

Now that Alberta has increased pipeline capacity and gas has the ability to move to market, there is a correlation between the TEP basis and Empress pricing. SaskEnergy anticipates that the TEP basis will continue to follow pricing at Empress.

m) On page 13 SaskEnergy notes that "SaskEnergy must pay firm transportation charges to move the Alberta gas into Saskatchewan. These transportation costs are forecast to average \$0.39/GJ." How does this reconcile to the transportation costs ranging between \$0.489/GJ and \$0.523/GJ in Schedule 1.1? Please explain and include explanations for the variances.

These values are derived from taking the total receipt transportation cost and dividing it by the total volume purchased. The posted toll for this firm transportation is ~\$0.39 per GJ however because SaskEnergy contracts for additional firm transportation in case of colder than normal weather, SaskEnergy may not utilize all of the transportation therefore equating to a higher per GJ cost. SaskEnergy must pay for this transportation whether it is utilized or not.

n) On pages 9 and 10 SaskEnergy notes that it currently contracts for 200,000 GJ/day of firm transportation capacity from Alberta and approximately 70,000 GJ/day of the 200,000 GJ/day of firm transportation contracted from Alberta is reserved for potential incremental winter gas purchase requirements.

i. Please confirm that the transportation costs are based on 200,000 GJ/day firm transportation capacity contract regardless the actual volume transported. If not, please explain.

The firm transportation costs are based on the contracted 200,000GJ/day.

ii. What is the added cost for 2021/22 and 2022/23 gas years to have 70,000 GJ/day of incremental capacity?
The costs for having this incremental capacity are approximately \$9.9 million per year and accounted for in the firm transportation costs.

o) Slide #10 of the SaskEnergy September 15, 2021 presentation shows that only in 2013/14 the full transportation capacity was used. If there is no incremental capacity contract, can SaskEnergy still access gas purchases? Or will it have limited access?

If there is no incremental capacity contracted, SaskEnergy would not have access for additional gas purchases because there is currently no additional NGTL transportation available. In the January 2018 open season, SaskEnergy made a decision to contract for additional transportation because it was unclear when more transportation would become available, and it was unclear how much

Saskatchewan production would be available.

p) Please explain how this 200,000 GJ/day firm transportation capacity contract relates to the maximum daily requirements shown on page 11. Does this cover “annual base supply 154,000 GJ/day” plus portion of gas retailers and sort purchases? Please elaborate.

The firm transportation of 200,000 GJ/day does cover the 154,000 GJ/day plus the spot purchases of 29,000 GJ/day. It does not cover any transportation for the gas retailers. The remaining contract volume is required for a colder than normal winter, as opposed to peak day.

q) On page 11 of 2018 Commodity and Delivery Service Rate Application SaskEnergy noted that firm transportation capacity from Alberta will be increased from 150,000 GJ/day to 170,000 GJs/day effective November 1, 2018. The current Application shows the firm transportation capacity contract was increased to 200,000 GJ/day.

i. When was the firm transportation capacity increased to the current 200,000 GJ/day?

The firm transportation increased to 200,000 GJ/day on November 1, 2020, after being increased to 180,000 GJ/day on November 1, 2019.

ii. What is the rationale for this increase considering the maximum daily requirements only increased from 605,000 GJ/day in 2018 application to 608,000 GJ/day in the current Application?

SaskEnergy increased its firm transportation contract to ensure security of supply. With Saskatchewan production decreasing, and the difficulty in obtaining additional firm transportation from Alberta, SaskEnergy had to make the decision in January 2018 based an open season for NGTL transportation from Alberta. SaskEnergy made the decision to increase its firm transportation capacity from Alberta reducing its reliance on declining production in Saskatchewan.

iii. What is the annual cost to customers from this increase [170,000 GJs/day to 200,000 GJs/day] for each 2021/22 and 2022/23 gas years?

The annual cost to customers is approximately $4.2 million each year. It is offset through less Saskatchewan gas purchases, and allows for security of supply during a cold winter.

r) The figure on page 13 of the Application shows $9.9 million "incremental contracted transport for security of supply".

i. Please explain if this $9.9 million is included in cost of gas. If yes, where is it reflected? If not, who pays for this cost?

This cost is included in Receipt Transportation costs in the Cost of Gas purchased in Schedule 1.1.

ii. Is this annual cost or for the period from November 1, 2021 to October 31, 2023? Please provide detailed calculations showing show $9.9 million was derived, including volumes and rates used.

These are estimated annual costs. See calculation below.

Volume	Current NIT to TEP Monthly Toll	Yearly Total
70000	$11.81	$9,920,232.00

iii. Is this cost over and above the 200,000 GJ/day firm transportation capacity contract?

This cost is included in the cost for the 200,000GJ/day of firm transportation.

iv. Is the "incremental contracted transport for security of supply" required due to assumed maximum daily requirements?

No, the volumes are based on allowing SaskEnergy to meets its customers needs in colder than normal winter (1 in 25) weather circumstances, providing security of supply. A secondary purpose is to meet maximum daily requirements, but only 29,000 GJ/day would be required for this purpose.

s) On page 11 of the Application SaskEnergy notes "should the winter weather be warmer than normal, SaskEnergy will typically exit the winter with higher than normal storage inventory levels, and then reduce its gas purchases accordingly over the summer period. Alternatively, if gas prices remained relatively high despite a mild winter in Saskatchewan, SaskEnergy may sell some of this excess gas during the winter period." Please confirm that the margin from these sales are included as an offset to the delivery service costs [Asset Optimization revenues]. If not confirmed, please explain where the profits from these sales are reflected.

The gain on these sales is accounted for by reducing the cost of gas purchased and flows back through to SaskEnergy's commodity rate.

t) On page 12 SaskEnergy notes that the annual contracts allow SaskEnergy to adjust to customer migration to/from SaskEnergy's regulated commodity service. SaskEnergy's September 15, 2021 presentation slide #21 notes that if some customers that buy gas from retailers return to SaskEnergy then the impact could be 2 to 4 PJs of gas required to be purchased at market prices.

i. For the last five years how many customers moved to retailers and how many returned to SaskEnergy. What is the net impact to volume of gas purchased from these changes?

Please see gas retailer annual loads below. Based on SaskEnergy's proposed rate and where the market currently is, SaskEnergy anticipates there may be additional customer load coming back to SaskEnergy from gas retailers.

Year	Total Retailer Volume (PJ)
2015/16	9.7
2016/17	11.0
2017/18	13.0
2018/19	14.6
2019/20	14.3
2020/21	12.7

ii. What would be added cost if SaskEnergy is required to buy additional 2 to 4 PJs of gas at market prices for the added customers?

As of September 14, the added annual cost to purchase two additional PJs of gas would be $8 million, and would be offset by commodity revenue of $6.3 million, leaving a net cost of $1.7 million. Four additional PJs would be exactly double that amount, or a net cost of $3.4 million.

u) On page 12 under Gas Purchase Portfolio SaskEnergy notes that the contracts "of one-year or less in duration minimize costs, as potential premiums associated with long-term contracts are avoided." On the same page under Gas Pricing

SaskEnergy also notes that "in the last few years SaskEnergy has also been entering into multi-year fixed price physical purchase contracts as part of the SaskEnergy's Gas Purchase and Price Risk Management Strategy." If the contracts one-year or less in duration minimize costs why pursue multi-year contracts?

As part of SaskEnergy's Price Risk Management Strategy, SaskEnergy purchases long-term fixed price contracts to lock in the price in the future.

The premium SaskEnergy is referring to in the Application is the premium of Saskatchewan gas to an AECO index.

v) The figure on page 13 of the Application shows $0.14/GJ "transport insurance". Please explain what this cost relates to.

Please note the text box in the chart you are referring to in the Application was mistakenly not updated. The $0.14/GJ you are referring to is the $9.9 million is now $0.18/GJ and refers to the additional 70,000 GJ/d of transport contracted from Alberta.

i. Is this paid to TransGas?

This cost is associated with the additional transportation SaskEnergy holds from Alberta with TransGas for colder than normal weather and is paid to TransGas.

ii. Is the rate approved as part of TransGas rates?

Yes, and the rate paid to TransGas and is the posted rate.

5. Reference: Load Forecast

a) Information Available from Schedules 1.0 and 2.0 of the Application show month-to-month variations in gas sales as shown in table below.

i. Please explain the lower sales forecast for the month of October in 2021, 2022 and 2023 compared to actuals in 2019 and 2020.

October was colder in 2019 and 2020 which resulted in higher actual sales than forecast. The forecasts in 2021, 2022 and 2023 are comparable with the forecasts for 2019 and 2021.

ii. Please explain the underlying reasons for high sales in February 2019.

Overall, the month of February was 40% colder than normal with temperatures reaching -40 degrees Celsius for an extended period. SaskEnergy also observed its peak day during this month.

iii. Please explain why the sum of Nov-Oct sales for 2019/20 and 2020/21 do not reconcile to totals.

Gas Year	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Total
2018/19	6,942	8,019	9,700	13,323	6,509	3,563	2,152	2,111	936	1,027	1,709	4,993	60,985
2019/20	6,487	9,617	9,586	7,789	6,140	4,653	1,861	3,061	952	848	1,703	4,690	57,454
2020/21	6,711	8,137	8,579	9,962	5,692	3,894	2,189	1,777	987	996	1,692	3,834	54,518
2021/22	6,519	9,002	9,650	7,984	6,536	3,563	1,829	1,571	976	985	1,678	3,808	54,100
2022/23	6,486	8,958	9,601	7,946	6,505	3,557	1,826	1,568	975	963	1,675	3,802	53,861

The monthly numbers are correct. In the 2019-20 and 2020-21 years, there was a formula error in the total calculation which is displayed in the schedule. There are no dependents on the total therefore this error did not impact any other calculations.

b) On page 8 of the Application SaskEnergy notes that the residential use per customer has declined steadily over the past several years and the decline is expected to continue during the forecast period. What is SaskEnergy's understanding regarding the reasons for the decline in use per customer [efficiencies, environmental considerations from customers, impact of rates, etc.]?

For a number of years, customer usage has declined across North America as end users acquire more energy efficient furnaces and appliances, install programmable thermostats, improve insulation in homes, reduce hot water usage, and generally have increased awareness of their energy consumption. New customer home constructions, as well as multi-unit dwellings use considerably less natural gas than existing customers and some are also replacing older less energy efficient homes.

c) Please provide further details regarding how the November 2021 to October 2022 and November 2022 to October 2023 forecast sales (in GJ) as provided in Schedule 1 were derived. If available, please provide a load forecast model.

The load forecast model is used to derive the forecast sales (in GJ) that are provided in Schedule 1. The forecast sales shown are determined by dividing the commodity rate from the commodity sales revenue that was derived from the forecast sales.

i. Please provide the sales forecast by customer class and reconcile to the information provided in Tab 4 of the Application by rate class.

The information provided in Tab 4 of the Application is based on SaskEnergy's load forecast that separates the forecast by customer class. The forecast sales in Schedule 1 utilizes this information but does not separate the information by customer class since the commodity rate is the same for all customer classes.

6. Reference: Renewable Natural Gas

a) Please explain if the Renewable Natural Gas (RNG) strategy is a government mandated program or initiated by SaskEnergy.

Renewable Natural Gas is an initiative of SaskEnergy, and is in the very early information gathering stages. No strategy has yet been developed.

i. Was it approved by SaskEnergy's Board or the provincial government?

No strategy has yet been developed.

ii. Please provide a copy of the noted strategy.

SaskEnergy is in the early stage of reviewing Renewable Natural Gas (RNG). Part of the RNG review process includes discussing the potential to offer RNG as an opt-in program with the Saskatchewan Rate Review Panel (Panel). After the Panel has considered the potential for an RNG service offering from a regulatory perspective, SaskEnergy would continue to study the issue internally prior to bringing a program forward for approval through its governance process.

b) Please explain why SaskEnergy is implementing this program at this time.

Natural Gas regulators in Canada have commented on the appropriateness of RNG programs in recent years (see question C below for additional information). SaskEnergy is interested in having the Panel comment on the potential to offer

RNG in Saskatchewan.

c) On page 16 of the Application SaskEnergy notes that the proposed strategy is "in alignment with what some other natural gas utilities are now doing."

i. Please provide details of the similar programs developed and offered in other jurisdictions.

British Columbia: Fortis BC developed its RNG program in 2011. Fortis BC customers can choose to designate 5, 10, 25, 50 or 100 per cent of the natural gas they use as RNG. Customers also receive a credit on the BC carbon tax on their bill, depending on the RNG blend they choose.

Quebec: Energir has committed to have 5% of the gas injected into its existing network be RNG by 2025, replacing traditional natural gas. Energir customers can also sign up for a wait list to have a portion of their household consumption be fed by RNG. Customer requests are filled on a first-come first-enrolled basis.

ii. What are the prices offered in other jurisdictions under these programs?

British Columbia: As of January 1, 2021, Fortis BC customers who choose to designate a percentage of their natural gas use as RNG will pay a rate of $11.830 per GJ for the Cost of biomethane on their natural gas bill.

Quebec: Energir customers pay $13.71 per GJ.

iii. Were the programs in other jurisdictions were fully subscribed?

British Columbia: Fortis BC indicates on their website that the RNG program is currently closed to new subscribers until additional supply can be brought online. As of September 2018, Fortis BC indicated on its website that it had 10,000 customers in its RNG program.

Quebec: Energir has a wait list for residential and commercial customers that desire RNG. SaskEnergy has not been able to determine the number of Energir Customers currently enrolled in its RNG program.

d) On page 16 of the Application SaskEnergy notes that it is considering purchases of up to 100,000 GJ/year of RNG, from Saskatchewan producers, at a maximum cost of $30/GJ.

i. Would SaskEnergy conduct some type of proposal or tender for qualifying producers? Please provide details.

SaskEnergy is in the early stages of investigating offering RNG. There have been no discussions yet as SaskEnergy is still in the information gathering stage.

ii. Please provide details regarding how the 100,000 GJ/year was estimated. Please include the number of producers estimated and any purchases forecast.

Fortis BC has indicated that RNG supply is limited within British Columbia with an annual production of approximately 500,000 GJ/year. Currently SaskEnergy has no knowledge of any RNG production in Saskatchewan, and the 100,000 GJ/year threshold is just a guesstimate at this point in time.

iii. Please explain how the $30/GJ cost was determined. Is this what the producers will get paid or does this include provision for SaskEnergy costs for program implementation?

The $30/GJ cost was suggested for consideration by the Panel to mirror the approach in British Columbia. FortisBC can pay up to $30 per gigajoule (GJ) for pipeline quality, purified biomethane.

iv. What is the cost for 100,000 GJ/year at $30/GJ?

The cost would be $3,000,000.

v. Are there any other added costs to customers from this program [e.g., SaskEnergy admin costs such as for implementation, billing and quality monitoring, etc.]?

SaskEnergy will determine the administrative structure required for this program after it has more information.

e) On page 16 of the Application SaskEnergy notes that “customers could select what percentage of RNG they would like to blend with their existing gas stream; the costs of the RNG would be billed directly to these customers. If the program is not fully subscribed, the remaining costs would be blended into SaskEnergy’s cost of gas sold and included in the commodity rate. The impact on costs to the commodity rate could range from zero to $0.06/GJ."

i. Did SaskEnergy survey customers to see if there is any interest for purchasing RNG? If yes, please provide survey results. If not, please explain why not.

SaskEnergy has not surveyed customers at this point. Once the Panel comments on the appropriateness of RNG, SaskEnergy will review the issue further prior to bringing a program forward through its governance process.

ii. Please confirm whether or not any costs related to RNG are included in the cost of gas in this Application. If not, please explain how SaskEnergy is proposing to collect the cost for purchases that are not fully subscribed.

There are no costs associated with RNG within the Rate Application. No program has yet been developed.

iii. Please confirm that $0.06/GJ is about 1.8% of the proposed commodity rate. If not, please provide percentage.

$0.06/GJ is approximately 1.9% of the proposed commodity rate.

iv. Please also provide bill impact to average residential customers if the program is not fully subscribed.

SaskEnergy does not have enough information yet to determine the impact.

v. Could the 100,000 GJ/year target be increased in future years? If yes, how is SaskEnergy planning to mitigate any ratepayer impacts from this program?

The 100,000 GJ/year is not yet a target, but only a talking point with the Panel. It is too early to comment on such details.

f) On page 16 of the Application SaskEnergy notes that "RNG needs to meet gas quality specifications to ensure that it does not have adverse effects on the distribution system or its customer's natural gas appliances." How is SaskEnergy planning to monitor the quality specifications and lower the risks to the customers?

RNG producers in Saskatchewan would transport their supply to TEP through TransGas facilities. TransGas has equipment in place for measuring gas quality at certain locations.

7. Reference: Interest and Operating Expenses

a) Please explain why an 18% increase in Operating Maintenance and Admin Expenses is assumed [$1.555 million for 2021/22 and 2022/23 gas year compared to $1.315 million for 2020/21 gas year], and the underlining assumptions for the increase?

The Operating, Maintenance and Administrative Charges, Bad Debt Expense and Late Payment Revenues used in Schedule 1.0 were preliminary budget numbers as the budget had not been finalized at the time of determining the commodity rate. The numbers in Tab 3 are the finalized budget numbers.

b) With reference to Operating Maintenance and Admin Expenses:

i. Has there been any change in the costs allocated or the basis of allocation since the last application that impacted the forecast costs?

No, there have not been any changes since the last application.

ii. Please outline the extent of any changes in allocation and the rationale for the change.

There have not been any changes.

c) Please explain why SaskEnergy did not use Operating, Maintenance and Administrative Charges, Bad Debt Expense and Late Payment Revenues from Tab 3 of the Application in computing Schedule 1.0.

The Operating, Maintenance and Administrative Charges, Bad Debt Expense and Late Payment Revenues used in Schedule 1.0 were preliminary budget numbers as the budget had not been finalized at the time of determining the commodity rate. The numbers in Tab 3 are the finalized budget numbers.

i. Operating Maintenance and Admin Expenses in Tab 3 is $1.385 million for 2021/22 and $1.400 million for 2022/23, while Schedule 1.0 uses $1.555 million for both 2021/22 and 2022/23.

An updated Schedule 1.0, Schedule 1.1 and Schedule 3.0 are provided in

c) part iii.

ii. Similarly Bad Debt Expense and Late Payment Revenues in Schedule 1.0 also differ from forecast included in Tab 3.

An updated Schedule 1.0 is provided in c) part iii.

iii. Please provide revised version of Schedule 1.0, Schedule 1.1. and Schedule 3.0 using Operating, Maintenance and Administrative Charges, Bad Debt Expense and Late Payment Revenues from Tab 3 of the Application.

Schedule 1.0
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SaskEnergy Incorporated
Forecast Cost of Gas Sold ($000's)
November 1, 2021 - October 31, 2022

		1	2	3	4	5	6	7	8	9	10	11	12	13
Line	**Description**	**Nov-21**	**Dec-21**	**Jan-22**	**Feb-22**	**Mar-22**	**Apr-22**	**May-22**	**Jun-22**	**Jul-22**	**Aug-22**	**Sep-22**	**Oct-22**	**TOTAL**
1	Saskatchewan Purchases	$3,449	$3,564	$3,564	$3,219	$3,564	$2,554	$2,639	$2,554	$2,639	$2,639	$2,554	$2,639	$35,574
2	Alberta Purchases	$10,761	$11,120	$11,120	$10,044	$11,120	$8,688	$8,977	$8,688	$8,977	$8,977	$8,688	$8,976	$116,137
3	Price Risk Management (Inflows)/Outflows	($3,517)	($3,635)	($3,635)	($3,283)	($3,635)	$0	$0	$0	$0	$0	$0	$0	($17,704)
4	Costs upstream of TEP	$2,307	$2,384	$2,384	$2,153	$2,384	$2,307	$2,384	$2,307	$2,384	$2,384	$2,307	$2,384	$28,069
5	**Cost of Purchase Gas**	**$13,000**	**$13,433**	**$13,433**	**$12,133**	**$13,433**	**$13,548**	**$14,000**	**$13,548**	**$14,000**	**$14,000**	**$13,548**	**$13,998**	**$162,074**
6	Storage Withdrawal (Injection)	$6,160	$13,799	$15,982	$12,074	$5,905	($2,284)	($8,108)	($8,548)	($10,894)	($10,917)	($8,271)	($2,137)	$2,761
7	Gas in Storage Interest Expense	$4	$4	$4	$4	$4	$4	$4	$4	$4	$4	$4	$4	$52
8	Gas Supply Operating Maintenance & Admin Expenses	$115	$115	$115	$115	$115	$115	$115	$115	$115	$115	$115	$115	$1,385
9	Gas Supply Related Bad Debt Expense	$94	$130	$139	$115	$94	$51	$26	$23	$14	$14	$24	$55	$780
10	Less Gas Supply Related Late Payment Charges	($44)	($57)	($84)	($109)	($110)	($100)	($85)	($68)	($55)	($46)	($41)	($40)	($839)
11	Less Cost of Internal Usage	($192)	($260)	($331)	($315)	($369)	($266)	($247)	($154)	($93)	($43)	($99)	($106)	($2,475)
12	**Cost of Gas Sold**	**$19,137**	**$27,165**	**$29,259**	**$24,018**	**$19,074**	**$11,069**	**$5,707**	**$4,921**	**$3,091**	**$3,127**	**$5,280**	**$11,891**	**$163,739**

Volume (Gigajoules - 000s)

Line	**Description**	**Nov-21**	**Dec-21**	**Jan-22**	**Feb-22**	**Mar-22**	**Apr-22**	**May-22**	**Jun-22**	**Jul-22**	**Aug-22**	**Sep-22**	**Oct-22**	**TOTAL**
13	Customer Sales	6,519	9,002	9,650	7,984	6,536	3,563	1,829	1,571	976	985	1,678	3,808	54,100
14	Purchases (less Fuel Gas & Line Loss)	4,691	4,847	4,847	4,378	4,847	4,388	4,534	4,388	4,534	4,534	4,388	4,534	54,914
15	Cost of Purchase Gas (GJ)	$2.771	$2.771	$2.771	$2.771	$2.771	$3.087	$3.087	$3.087	$3.087	$3.087	$3.087	$3.087	
16	Storage Withdrawal (Injection)	1,893	4,241	4,912	3,710	1,815	(740)	(2,626)	(2,769)	(3,529)	(3,536)	(2,679)	(692)	0
17	Storage Withdrawal (Injection) Rate (GJ)	$3.254	$3.254	$3.254	$3.254	$3.254	$3.087	$3.087	$3.087	$3.087	$3.087	$3.087	$3.087	
18	Internal Usage	(65)	(86)	(109)	(105)	(126)	(86)	(79)	(49)	(29)	(14)	(31)	(34)	(814)

Note: Numbers may not add up exact due to rounding.

Schedule 1.0
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SaskEnergy Incorporated
Forecast Cost of Gas Sold ($000's)
November 1, 2022 - October 31, 2023

1		2	3	4	5	6	7	8	9	10	11	12	13	14
Line	**Description**	**Nov-22**	**Dec-22**	**Jan-23**	**Feb-23**	**Mar-23**	**Apr-23**	**May-23**	**Jun-23**	**Jul-23**	**Aug-23**	**Sep-23**	**Oct-23**	**TOTAL**
1	Saskatchewan Purchases	$2,657	$2,745	$2,745	$2,479	$2,745	$2,103	$2,173	$2,103	$2,173	$2,173	$2,103	$2,173	$28,372
2	Alberta Purchases	$9,648	$9,970	$10,005	$9,037	$10,005	$8,277	$8,553	$8,277	$8,553	$8,553	$8,277	$8,553	$107,708
3	Price Risk Management (Inflows)/Outflows	($2,092)	($2,162)	($2,162)	($1,952)	($2,162)	$0	$0	$0	$0	$0	$0	$0	($10,530)
4	Costs upstream of TEP	$2,307	$2,384	$2,384	$2,153	$2,384	$2,307	$2,384	$2,307	$2,384	$2,384	$2,307	$2,384	$28,069
5	**Cost of Purchase Gas**	**$12,520**	**$12,937**	**$12,973**	**$11,717**	**$12,973**	**$12,687**	**$13,110**	**$12,687**	**$13,110**	**$13,110**	**$12,687**	**$13,110**	**$153,619**
6	Storage Withdrawal (Injection)	$5,918	$13,178	$15,216	$11,505	$5,652	($2,147)	($7,597)	($8,009)	($10,204)	($10,226)	($7,750)	($2,012)	$3,524
7	Gas in Storage Interest Expense	$13	$13	$13	$13	$13	$13	$13	$13	$13	$13	$13	$13	$155
8	Gas Supply Operating Maintenance & Admin Expenses	$117	$117	$117	$117	$117	$117	$117	$117	$117	$117	$117	$117	$1,400
9	Gas Supply Related Bad Debt Expense	$66	$91	$98	$81	$66	$36	$19	$16	$10	$10	$17	$39	$548
10	Less Gas Supply Related Late Payment Charges	($44)	($57)	($84)	($109)	($110)	($100)	($85)	($68)	($55)	($46)	($41)	($40)	($839)
11	Less Cost of Internal Usage	($186)	($250)	($318)	($303)	($356)	($250)	($232)	($144)	($88)	($41)	($93)	($99)	($2,359)
12	**Cost of Gas Sold**	**$18,404**	**$26,029**	**$28,013**	**$23,021**	**$18,354**	**$10,356**	**$5,344**	**$4,611**	**$2,902**	**$2,937**	**$4,949**	**$11,127**	**$156,048**

Volume (Gigajoules - 000s)

Line	**Description**	**Nov-22**	**Dec-22**	**Jan-23**	**Feb-23**	**Mar-23**	**Apr-23**	**May-23**	**Jun-23**	**Jul-23**	**Aug-23**	**Sep-23**	**Oct-23**	**TOTAL**
13	Customer Sales	6,486	8,958	9,601	7,946	6,505	3,557	1,826	1,568	975	983	1,675	3,802	53,881
14	Purchases (less Fuel Gas & Line Loss)	4,646	4,801	4,812	4,346	4,812	4,385	4,531	4,385	4,531	4,531	4,385	4,531	54,694
15	Cost of Purchase Gas (GJ)	$2.695	$2.695	$2.696	$2.696	$2.696	$2.893	$2.893	$2.893	$2.893	$2.893	$2.893	$2.893	
16	Storage Withdrawal (Injection)	1,905	4,243	4,899	3,704	1,819	(742)	(2,626)	(2,768)	(3,527)	(3,534)	(2,678)	(695)	0
17	Storage Withdrawal (Injection) Rate (GJ)	$3.106	$3.106	$3.106	$3.106	$3.106	$2.893	$2.893	$2.893	$2.893	$2.893	$2.893	$2.893	
18	Internal Usage	(65)	(86)	(109)	(104)	(126)	(86)	(79)	(49)	(29)	(14)	(31)	(34)	(813)

Note: Numbers may not add up exact due to rounding.

Schedule 1.1
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SaskEnergy Incorporated
Forecast Gas Prices for
November 1, 2021 - October 31, 2022
Closing Prices as of August 3, 2021
$/Gigajoule

		1	2	3	4	5	6	7	8	9	10	11	12
Line	**Description**	**Nov-21**	**Dec-21**	**Jan-22**	**Feb-22**	**Mar-22**	**Apr-22**	**May-22**	**Jun-22**	**Jul-22**	**Aug-22**	**Sep-22**	**Oct-22**
1	AECO Forward Prices	4.088	4.088	4.088	4.088	4.088	2.962	2.962	2.962	2.962	2.962	2.962	2.962
	COST OF PURCHASE GAS												
2	Cost of Purchase Gas Before Financial Hedges	3.011	3.011	3.011	3.011	3.011	2.544	2.544	2.544	2.544	2.544	2.544	2.544
3	Change in Price due to Financial Hedges	(0.745)	(0.745)	(0.745)	(0.745)	(0.745)	0.000	0.000	0.000	0.000	0.000	0.000	0.000
4	Receipt Transport	0.489	0.489	0.489	0.489	0.489	0.522	0.522	0.522	0.522	0.522	0.522	0.522
5	Forecast Cost of Purchase Gas	2.754	2.754	2.754	2.754	2.754	3.067	3.067	3.067	3.067	3.067	3.067	3.067
6	Volume Adjusted Cost of Purchase Gas [1]	2.771	2.771	2.771	2.771	2.771	3.087	3.087	3.087	3.087	3.087	3.087	3.087
	COST OF GAS SOLD												
7	Purchase Price	2.771	2.771	2.771	2.771	2.771	3.087	3.087	3.087	3.087	3.087	3.087	3.087
8	% of Sales met with Purchases	71.0%	52.9%	49.1%	53.5%	72.2%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
9	Inventory Withdrawal Price	3.254	3.254	3.254	3.254	3.254	3.211	3.151	3.130	3.117	3.110	3.107	3.106
10	% of Sales met with Inventory	29.0%	47.1%	50.9%	46.5%	27.8%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
11	Cost of Gas Sold before OM&A	2.911	2.999	3.017	2.996	2.905	3.087	3.087	3.087	3.087	3.087	3.087	3.087
12	Interest, OM&A and Bad Debt Expense Less Late Payment Charges [2]	0.027	0.022	0.019	0.016	0.017	0.021	0.036	0.050	0.085	0.093	0.064	0.036
13	Forecast Cost of Gas Sold	$ 2.938	$ 3.020	$ 3.035	$ 3.012	$ 2.922	$ 3.109	$ 3.123	$ 3.137	$ 3.173	$ 3.180	$ 3.151	$ 3.124

1 The volume of purchase gas has been adjusted for Fuel Gas and Line Loss.

2 Interest, OM&A, Bad Debt Expense and Late Payment Charges are budgeted annually and calculated as equal monthly expenses. Due to the varying monthly sales volumes, the impact on the Cost of Gas Sold will be minimal during months where sales volumes are high and considerably greater when sales volumes are low.

Schedule 1.1
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SaskEnergy Incorporated

Forecast Gas Prices for
November 1, 2022 - October 31, 2023
Closing Prices as of August 3, 2021
$/Gigajoule

		1	2	3	4	5	6	7	8	9	10	11	12
Line	**Description**	**Nov-22**	**Dec-22**	**Jan-23**	**Feb-23**	**Mar-23**	**Apr-23**	**May-23**	**Jun-23**	**Jul-23**	**Aug-23**	**Sep-23**	**Oct-23**
1	AECO Forward Prices	3.242	3.242	3.242	3.242	3.242	2.504	2.504	2.504	2.504	2.504	2.504	2.504
	COST OF PURCHASE GAS												
2	Cost of Purchase Gas Before Financial Hedges	2.632	2.632	2.634	2.634	2.634	2.351	2.351	2.351	2.351	2.351	2.351	2.351
3	Change in Price due to Financial Hedges	(0.447)	(0.447)	(0.446)	(0.446)	(0.446)	0.000	0.000	0.000	0.000	0.000	0.000	0.000
4	Receipt Transport	0.493	0.493	0.492	0.492	0.492	0.523	0.523	0.523	0.523	0.523	0.523	0.523
5	Forecast Cost of Purchase Gas	2.678	2.678	2.679	2.679	2.679	2.874	2.874	2.874	2.874	2.874	2.874	2.874
6	Volume Adjusted Cost of Purchase Gas [1]	2.695	2.695	2.696	2.696	2.696	2.893	2.893	2.893	2.893	2.893	2.893	2.893
	COST OF GAS SOLD												
7	Purchase Price	2.695	2.695	2.696	2.696	2.696	2.893	2.893	2.893	2.893	2.893	2.893	2.893
8	% of Sales met with Purchases	70.6%	52.6%	49.0%	53.4%	72.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
9	Inventory Withdrawal Price	3.106	3.106	3.106	3.106	3.106	3.051	2.975	2.948	2.931	2.923	2.918	2.917
10	% of Sales met with Inventory	29.4%	47.4%	51.0%	46.6%	28.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
11	Cost of Gas Sold before OM&A	2.816	2.890	2.905	2.887	2.811	2.893	2.893	2.893	2.893	2.893	2.893	2.893
12	Interest, OM&A and Bad Debt Expense Less Late Payment Charges [2]	0.024	0.019	0.015	0.013	0.014	0.020	0.037	0.052	0.091	0.099	0.065	0.035
13	Forecast Cost of Gas Sold	$ 2.839	$ 2.908	$ 2.921	$ 2.900	$ 2.824	$ 2.913	$ 2.930	$ 2.945	$ 2.985	$ 2.992	$ 2.959	$ 2.928

1 The volume of purchase gas has been adjusted for Fuel Gas and Line Loss.
2 Interest, OM&A, Bad Debt Expense and Late Payment Charges are budgeted annually and calculated as equal monthly expenses. Due to the varying monthly sales volumes, the impact on the Cost of Gas Sold will be minimal during months where sales volumes are high and considerably greater when sales volumes are low.

Schedule 3.0

SaskEnergy Incorporated

Determination of Commodity Rate for
November 1, 2021 to October 31, 2023

Line	Description	Amount	Ref.
1	Estimated Balance of GCVA at October 31, 2021 (000's)	$18,811,695	Schedule 2.0: (P3, Col. 12, Line 20)
2	November 2021 to October 2023 Gas Cost Forecast (000's)	$ 319,878,881	Schedule 1.0: (P1, Col. 13, Line 12) + (P2, Col. 13, Line 12)
3	Total Forecast Costs to Recover (000's)	$ 338,690,576	Line 1 plus Line 2
4	November 2021 to October 2023 Forecast Sales (GJs - 000's)	107,980,597	Schedule 1.0: (P1, Col. 13, Line 13) + (P2, Col. 13, Line 13)
5	November 2021 to October 2023 Monthly Weighted Cost per Unit of Sales	**$3.137**	Line 3 divided by Line 4
6	Indicative Two Year Commodity Rate	**$3.14**	
7	Customer Commodity Rate Equivalent (Heating Value = 39.90 MJ/m^3)	**12.51**	cents per cubic metre

Notes:

1. Numbers might not add precisely due to rounding.

2. SaskEnergy purchases natural gas on an energy basis (GJs) and bills its customers on a volume basis (cubic metres). The Heating Value used to convert energy to volume is a forecast based on the previous average volume-weighted twelve months.

3. The methodology is designed to target a zero GCVA balance at the end of the two year period (November 2021 - October 2023).

d) Please explain why the interest rate increases from 0.15% in October 2021 to 1.52% in November 2021 and further to 1.77% in January 2022, and provide the source for interest rate forecasts used?

The November 2021 forecast and the January 2022 forecast were preliminary estimates based on longer term borrowing rates instead of short term borrowing which is shown in October. A revision to the interest rates and the associated inventory carrying costs will be provided for November 2021 through to October 2023.

An average of five major financial institutions (TD, RBC, BNS, CIBC, BMO) is used to determine the interest rate forecast.

The updated interest rates have been used in the updated schedules provided in the above response for c) part iii. The updated interest rates are as follows:

Nov-21	0.16%	Nov-22	0.53%
Dec-21	0.16%	Dec-22	0.53%
Jan-22	0.23%	Jan-23	0.78%
Feb-22	0.23%	Feb-23	0.78%
Mar-22	0.23%	Mar-23	0.78%
Apr-22	0.26%	Apr-23	1.03%
May-22	0.26%	May-23	1.03%
Jun-22	0.26%	Jun-23	1.03%
Jul-22	0.36%	Jul-23	1.03%
Aug-22	0.36%	Aug-23	1.03%
Sep-22	0.36%	Sep-23	1.03%
Oct-22	0.53%	Oct-23	1.03%

e) SaskEnergy forecasting substantial reductions in both bad debt expense and late payment charges for 2021/22 and 2022/23 gas years compared to the actuals in 2019/19 and 2019/20 actuals and 2020/21 full year forecast.

i. Please explain how the bad debt expense forecast was calculated.

The bad debt expense forecast was calculated based on 0.5% of forecasted commodity revenues in 2021-22 and 0.3% of forecasted commodity revenues in 2022-23. SaskEnergy is forecasting customer arrears to decline compared to 2019/20 and 2020/21 actuals. Prior to the bill deferral payment program that was offered in March 2020, SaskEnergy realized bad debt expense that was 0.3% of actual commodity revenues in 2017/18 and 2018/19.

ii. Please explain how the forecast late payment revenue was calculated.

The late payment revenue forecast was calculated based on 0.5% of forecasted commodity revenues in 2021/22 and 2022/23.

iii. Please explain the substantial reduction in both bad debt expense and late payment charges for 2021/22 and 2022/23 gas years compared to the actuals in 2018/19 and 2019/20 actuals and 2020/21 full year forecast.

In March 2020, in response to the global pandemic, SaskEnergy implemented the Government of Saskatchewan's Crown Utility Interest Waiver Program. Under this program, any interest fees or late payment charges a customer accrues were waived. For customer with existing arrears and collections activities (including disconnections for non-payment) were put on hold. This impact resulted in lowers actuals than forecast. The bill payment deferral program also led to a discontinuation of late payment charges for a period of time in 2020-21.

8. Gas Cost Variance Account

a) Please provide the actual heat value for last five years and provide the estimated impact of the actual heat value [compared to heat value in rates] to the GCVA balance.

Year	Heat Value
2016-17	38.52
2017-18	38.61
2018-19	38.86
2019-20	39.19
2020-21	39.63

The estimated impact of the actual heat value to the GCVA balance is $13.2 million (owing to SaskEnergy from customers) for the last five years.

b) Please provide details if the internal use includes any use for SaskEnergy subsidiaries and/or departments other than the distribution division. If yes, please explain why.

The cost amounts for internal use provided relate only to the distribution division.

i. Please provide details regarding how the internal use in shared properties are estimated.

Property expenses, including internal usage, related to properties shared with other subsidiaries are allocated by square footage to subsidiaries.

c) Please provide details regarding the calculation of Cost of Internal Usage for the period from November 2018 to October 2023.

The Cost of Internal Usage is derived by multiplying the SEI Internal Usage by the Cost of Gas Sold (COGS) with Internal Usage volume.

The SEI Internal Usage is derived from the load forecast and is based on previous year's actuals. The COGS with Internal Usage is derived by taking the total COGS with Internal Usage and dividing by the volume.

i. Please explain correlation between volume of internal usage and cost of internal usage in Schedule 2.0 [for example, why April 2020 shows volume as negative 42,000 GJ with cost as negative $0.116 million; while May 2020 shows positive volume at 408,000 GJ with cost as negative $0.115 million].

The internal usage volumes (line 26 on Schedule 2.0) take into account the storage withdrawals and injections and correspond accordingly.

d) On page 6 SaskEnergy notes that Cost of Internal Usage includes Lost and Unaccounted for Gas. Schedule 1.1., note 1 notes that the volume of purchase gas has been adjusted for fuel gas and line loss. What are the differences between losses included in Cost of Internal Usage and losses included in cost of purchase gas?

The line losses included in purchase gas are those paid to a third party such as TransGas, required to transport the natural gas. TransGas updates their fuel and line loss rate each month and is currently set at 0.9%. Internal usage is natural gas used in the internal operations of SaskEnergy. It is therefore removed from the cost of gas and added to delivery expenses.

e) Please explain why the storage volume in March 2019 went to "0" as illustrated in Schedule 2.1. Was this required for maintenance purposes?

February 2019 was colder than normal and therefore SaskEnergy drew its storage inventory down more than normal and exited winter with close to zero gas in the ground. That inventory level is reflected in the Schedule 2.1.

f) Please explain the losses of $0.843 million included in Schedule 2.0, page 2 of 3 [line 17] for the 2019/20 gas year.

This is the difference between additional gas purchases and the SaskEnergy commodity rate at the time.