1. Reference: 1st Round Information Request #1 [Delivery Service Rate Overview]

a) The table provided shows that in the 2018-19 Business Plan for the Distribution Division forecast net earnings were $57.2 million for 2018-19 and $46.3 million for 2019-20. These forecasts are higher compared to the forecast included in Schedule 4.6 of the Application:

i. Please reconcile revenues and expenses included in the 2018-19 Business Plan and the Application and explain any key differences.

The response to 2018 Delivery Rate Application 1st Round Information Request 1 (a) is consistent to International Financial Reporting Standards and therefore consistent to the audited financial statements prepared by SaskEnergy. The reconciliation of revenues and expenses included in the 2018-19 business plan as per 2018 Delivery Rate Application Information Request 1 (a) are as follows:

2018-19 Net Income in the 2018-19 Business Plan - $57.2 million

Less Customer Contribution Revenue = $23.1 million

Less Commodity Margin = $4.7 million

Less 2.6% Delivery Rate Increase Effective November 1, 2018 Not Proceeding = $4.1 million

Less a Delivery Revenue over recovery (i.e.: above target ROE) - $1.5 million

Less Lower Projected Rate Base therefore Lower Return on Equity Target = $1.1 million

Less Internal Gas Usage = $1.7 million

Less Contract Industrial (Non – Delivery) margin = $0.7 million

Plus Amortization of Customer Contributions = $6.7 million

Plus Allocation of Operating and Maintenance Expense to Commodity and Contract Industrial = $1.8 million

Plus Allocation of Bad Debt Expense to Commodity - $0.9 million

Plus Allocation of Interest to Commodity - $0.3 million

Please reference 2018 Delivery Rate Application 2nd Round Information Request 1 (a) (ii) to recognize the key differences.

ii. Please explain how SaskEnergy is expecting to achieve net income from operations at $57.2 million for 2018-19 and $46.3 million for 2019-20.

Consistent to the response to 2018 Delivery Rate Application 2nd Round Information Request 1 (a) (i), the increased net income is driven by customer contribution revenue recognition compared to the deferral and amortization of customer contributions, the non-core contract industrial margin, and the commodity margin which are all not included in the delivery net income projection.

iii. Please provide forecast ROEs for 2018-19 and 2019-20 based on the Business Plan forecast provided in response to Delivery 1st Round Information Request 1(a) and deemed equity ratio. Please compare this to the forecast ROE in the application.

The forecasted return on equity for 2018-19 and 2019-20 based on the Business Plan forecast are as follows:

2018-19 – 10.7%

2019-20 – 8.2%

The forecasted return on equity for 2018-19 and 2019-20 based on the deemed equity ratio is as follows:

2018-19 – 15.8%

2019-20 – 11.5%

The forecasted return on equity in the application is as follows:

2018-19 – 8.3%

2019-20 – 8.3%

iv. Please explain the assumptions used for rate increases for 2019-20 through 2022-23 in the Business Plan forecasts provided in response to Delivery 1st Round Information Request 1(a).

The assumptions for rate increases in the 2018-19 Business Plan are as follows:

2019-20 – 4.8%

2020-21 – 4.1%

2021-22 – 4.1%

2022-23 – 4.0%

v. Please provide a detailed breakdown of the other revenues included in the Business Plan forecasts provided in response to Delivery 1st Round Information Request 1(a).

The breakdown of other revenues included in the Business Plan forecasts provided in response to Delivery 1st Round Information Request 1 (a) is as follows:

Commodity Sales = 177.1 million

Contract Industrial Sales = 20.7 million

Customer Contribution Revenue = 23.1 million

b) Please provide details on how SaskEnergy estimated the impact of accounting standard changes shown in response to Delivery 1st Round Information Request 1 (b) and 14(u). Please also provide details regarding the impact to the PP&E, depreciation expenses and computation of rate base.

As required in the standard, SaskEnergy has transferred the lease payments from operating and maintenance expense to capital expenditures. The impact to PP&E is an increase of $8.8 million in capital additions which is composed of $2.4 million in area office buildings, $6.2 million for SaskEnergy Place, and $0.2 million for parking lots based on lease renewal assumptions provided by Buildings and Security. The impact to depreciation expense as shown in 2018 Delivery Rate Application 1st Round response 1 (b) is $2.9 million assuming a lease term of approximately 3 years. The rate base will increase by approximately $5.9 million in 2019-20 as $8.8 million in capital additions will increase gross PP&E partially offset by a $2.9 million increase in accumulated depreciation.

As noted in the response to the 2018 Delivery Rate Application 1st Round response 1 (b), the accounting treatment and related amounts are based on initial analysis and a further detailed review of the standard is required to determine the specific impact.

c) In response to Delivery 1st Round Information Request 1 (e) SaskEnergy shows that Vacancy Management resulted in $3.1 million actual savings compared to the 2017-18 test year. In 2017 Delivery Rate Application response to 2nd Round Information Request 3 (c), SaskEnergy indicated that the 2017-18 fiscal year includes a vacancy rate adjustment of $3.316 million and Pre-ask #4 shows that the actual vacancy rate adjustments were at $3.060 million. Please explain how the referenced numbers relate to the $3.1 million Vacancy Management savings in 2017-18.

The vacancy rate adjustment of $3.316 million referenced in the 2017 Delivery Rate Application 2nd Round Information Request 3 c and the actual vacancy rate adjustment shown in Pre-Ask #4 are comparable as they are both referencing planned vacancy management. The $3.316 million and the $3.060 million are applicable to April 2017 to March 2018. The $3.1 million vacancy management savings in response to 1st Round Information Request 1 (e) is vacancy management over and above the planned vacancy management assumed in the 2017-18 test year (November 2017 to October 2018).

d) Please explain in detail the $2.4 million actual lower depreciation expense compared to the forecast as indicated in response to Delivery 1st Round Information Request 1(e). Does this relate to lower than expected investment volumes?

Yes, this relates to lower than expected investment volumes in the categories mentioned in the response to Information Request 1 (e). Expected investment in communication and collaboration infrastructure was not as immediate as originally planned partially driven by a shift in priority to the Management of Change initiative projected to be ongoing into the 2018-19 fiscal year. The purchase of SaskEnergy Place was included in the 2017-18 test year forecast and therefore depreciation of that investment was included in the forecast. This purchase will not happen in the 2017-18 test year. Customer growth in rural services is projected to be lower than expected in the 2017-18 test year. Transportation vehicle investment and/or heavy work equipment investment is expected to be lower as the volume of planned replacement pertaining to heavy work equipment is expected to be lower than assumed in the 2017-18 test year.

e) With reference to the response to Delivery 1st Round Information Request 1(c), (d) and (e):

i. Please outline the process steps taken in 2016-17 and 2017-18 to prepare the business plan and delivery rate application; please indicate relative to these steps when SaskEnergy was directed by its shareholder to reduce budgeted expenditures and the quantum of the impact in each case.

In 2016-17 and 2017-18, SaskEnergy's business plan and delivery rate application were put forward to the Executive team, the Audit and Finance Committee for review and to the Board of Directors for approval of the business plan and the delivery rate applications.

The process started in June of each year with the Board of Directors approving SaskEnergy's business plan in November 2015 and November 2016. SaskEnergy's shareholder approved SaskEnergy's business plan in December 2015 for the 2016-17 business plan and in January 2017 for the 2017-18 business plan. Prior to the beginning of the fiscal year April 2016, SaskEnergy was directed by the shareholder to increase their net income targets that were approved in December 2015. As shown in 2018 Delivery Rate Application Information Request 1 (i), the quantum of savings was $7.0 million. In addition, in October 2016, there was a second request for an incremental restraint savings of $2.4 million. During the fiscal year 2017-18, the shareholder expected higher net income than was approved in January 2017. As shown in 2018 Delivery Rate Application Information Request 1 (i), the quantum of savings was $4.0 million. In each instance, these are not reduced budgeted expenditures therefore would not be reflected in the original business plan and are not in the delivery rate applications.

ii. Please confirm that the total impact of restraint measures in 2017-18 was $6.3 million.

The total impact of restraint measures is $4.0 million in the 2017-18 fiscal year (April 2017 to March 2018) and $2.3 million in the 2017-18 test year. These amounts are not additive as explained in 2018 Delivery Rate Application Round 2 Information Request 1 (f).

iii. Please explain the difference in the restraint measures outlined in part (c) versus part (d). Were the measures outlined in the response to part (d) taken later in the fiscal year?

Please reference the answer to 2nd Round Information Request 1 (e) part (b) above.

f) With reference to the response to Delivery 1st Round Information Request 1(i), please confirm whether the total restraint measures in 2016-17 and 2017-18 are correct or should be higher given response to queries below.

i. 2017 Delivery Rate Application 2nd Round Information Request 1(e) noted $7 million of restraint 2016-17; the response to 2018 Delivery 1st Round Information Request 1(h) implies further restraint measures (O&M variance increases from $5.095 million to $9.326 million). Please discuss this variance and provide any relevant updates to the table provided in the response to Delivery 1st Round Information Request 1(i).

SaskEnergy does not forecast restraint measures in their delivery rate applications. Restraint measures were executed by SaskEnergy after their business plans including their net income targets are approved by SaskEnergy's shareholder. The O&M variance shown in response to 2018 Delivery 1st Round Information Request 1 (h) is indicative of restraint and internal cost management not forecasted in the delivery rate application. In addition, in October 2016, there was a second request for an incremental restraint savings of $2.4 million.

ii. The response to 1st Round Information Request 1(c) and (d) indicate restraint measures in 2017-18 total $6.3 million and not $ 4 million as noted in the response to Delivery 1st Round Information Request 1(i). Please explain the difference and provide any updates to the table provided in the response to Delivery 1st Round Information Request 1(i).

The response to 1st Round Information request 1 c indicates restraint measures in fiscal year (April 2017 to March 2018) 2017-18 of $4.0 million consistent to 1st Round Information request 1 (i). The response 1 d is not incremental restraint measures to the $4.0 million consistent to 1st Round Information request 1 (i), it rather is identifying restraint applicable to the 2017-18 test year (Nov 2017 to Oct 2018) that was not included in the 2017-18 forecast included in the 2017 Delivery Rate Application. Restraint measures are not forecasted by SaskEnergy in their delivery rate applications.

iii. The response to Delivery 1st Round Information Request 1(i) indicates "for 2018-19 and 2019-20, there are no further restraint measures or other cost reductions being implemented or expected to be implemented in these years." The response to Delivery 1st Round Information Request 2(d) notes "net income targets were expectations by our shareholder to achieve higher net income than planned in the approved budget" and "2018-19 net income target is set and 2019-20 will be determined once the business plan has been finalized." Please reconcile these statements and if required provide any updates to the response to Delivery 1st Round Information Request 1(i).

SaskEnergy's shareholder approves net income targets each year presented to them by SaskEnergy. In the past (i.e.: 2015-16 through to 2017-18), those net income targets were revisited after they were approved by SaskEnergy's shareholder as heightened expectations of net income were asked of SaskEnergy to which they managed through fiscal restraint and general internal cost management. At this point in time, the 2018-19 target approved by SaskEnergy's shareholder as presented to them by SaskEnergy during business plan development has not been revisited.

2. Reference: 1st Round Information Request #2 [OM&A Costs]

a) In response to Delivery 1st Round Information Request 2 (b) SaskEnergy notes that safety continues to be at the forefront of incremental costs with a $0.4 million increase in line locating and a $0.6 million increase for odorant expense. What are the drivers for these increases?

Line Locating is a joint service initiative contracted out to Shermco Industries and the cost is billed to SaskEnergy based on the number of locates. The number of locates are projected to increase in 2018-19 compared to 2017-18 and in 2019-20 compared to 2018-19. Higher odorant costs are driven by a higher volume of odorant expected to be sourced from Arkema Canada Inc. Odorant puts a rotten egg smell into odourless natural gas to detect natural gas leaks.

b) With the reference to the response to 1st Round Information Request 2 (b) and Tab 9, please explain why charges to capital are expected to be lower in 2019-20 compared to 2017-18 actuals, while SaskEnergy's capital spending and labour costs have increased.

Capital spending is projected to increase which does reflect increased charges to capital in 2019-20 compared to 2017-18 actuals in distribution engineering, information systems and in the north and south construction departments. In 2017-18, there was higher than normal capitalization in the customer service and operations areas driven by the Distribution Work Management investment which was completed in 2017-18. The Distribution Work Management investment is not standard capital investment executed on an annual basis by SaskEnergy.

c) Have there been any changes to safety and awareness policies/programs or industrial best practices since the last Application? If yes, please indicate key drivers and related incremental costs or savings compared to the 2017-18 test year.

There is an increased focus on regulatory compliance which results in additional costs to safety and awareness policies/programs.

d) With the reference to the response to Delivery 1st Round Information Request 2 (c), please provide a comparison of total safety and awareness costs per customer for SaskEnergy from 2016-17 through 2019-20.

Total Safety and Awareness Costs per Customer				
	2016-17	2017-18	2018-19	2019-20
Total Safety and Awareness	$ 794,754	$ 794,594	$ 915,179	$ 1,167,546
Average # of Customers	390,886	394,592	398,434	402,069
Total Cost Per Customer	$ 2.03	$ 2.01	$ 2.30	$ 2.90

e) With reference to the response to 1st Round Information Request 2(b) please explain further what "hosting of technological solutions" entails, provide a rationale or justification for pursuing "hosting of technological solutions" at this time, the alternatives considered, and why this is the preferred approach. Please also include any economic justification for this approach.

Hosting entails the use of third party services to provide some or all of the services that have traditionally been provided internally. This includes utilizing third party data center facilities to host company owned hardware, vendor provided support for applications, and vendor provide hardware and software support.

Many providers have transitioned away from the traditional perpetual license model where you are able to purchase a license and pay maintenance and support costs in order to have the right to upgrades or new versions. Vendors are now providing licenses on a subscription model. Customers pay a regular fee (monthly is standard) for the right to use the software. Vendors provide regular upgrades and version changes that customers are required to accept. The applications are hosted and managed by the vendor with customers accessing them via Internet connections.

Changing business needs for accessibility and resilience of applications would require substantial investment by SaskEnergy in non-core assets like data centers in order to meet these needs. Our strategy is to transition alongside our key vendors to the hosted model. We currently have applications and hardware hosted and supported by third parties (CGI and SaskTel for example) and are evaluating appropriate timing for moving other key applications and infrastructure to this model.

f) With reference to the response to 1st Round Information Request 2(b) please explain if any portion of the costs related to "hosting of technological solutions" are capitalized or if all of the costs for "hosting of technological solutions" are included as an operation and maintenance expense.

All hosting costs of technological solutions are included as an operating and maintenance expense.

g) With reference to the response to 1st Round Information Request 2(b) please outline and explain the key drivers or requirements making up the $5.0 million cost for "hosting of technological solutions" in 2019-20 compared to 2017-18.

SaskEnergy is evolving to the hosted model for technology delivery. As key applications (Cybersecurity, OneWorld, DWM, GIS) and infrastructure require upgrades or replacement, we will be working with vendors and service providers to transition these systems. The shift from company owned software and equipment to vendor provided services shift costs that had traditionally been capital in nature to operating.

h) In response to 1st Round information request 2(f) SaskEnergy notes that the cost per full time equivalent is less than the cost per contractor.

i. Please quantify the cost savings and provide a business case assessment that supports the above statement (i.e., that a FTE is less costly than a contractor), including a detailed breakdown of costs per FTE used for the assessment and cost per contractor used for this assessment.

The list of added positions showing expected replacement of the external services for each position in dollars is as follows for 2019-20:

10 Business Process Advisors @ approximately $93 thousand per position in savings = $930 thousand in total savings

4 Engineers @ approximately $93 thousand per position in savings = $372 thousand in total savings

3 Computer Automated Drafting Technologists @ approximately $93 thousand in savings per positon = $279 thousand in total savings

The cost for each contractor is $103.50 per hour X 1,924 hours per year = $199,134 per contractor per year. The loaded cost (including benefits) for an FTE is $55 per hour X 1,924 hours per year = 105,820

ii. Please provide details regarding where the noted cost savings are included in the Application.

The noted cost savings are included in the contract services category within External Services in Tab 9 Page 2 in the application.

i) In response to 1st Round Information Request 2 (g) SaskEnergy lists the cost increases for software lease and maintenance costs. Were these cost increases forecast based on quotes from service providers or based on internal reviews? Please explain and provide details.

These costs are based on contracts and projections based on expected costs if contracts are not currently in place for the fiscal period in question. Where expected costs are used the estimates are based on historical activity, SaskEnergy discussions with vendors, and our understanding of the market for these services.

3. Reference: 1st Round Information Request #3 [Labour Costs]

a) With reference to Delivery 1st Round Information Request 3(a) and (b) please provide a further explanation of vacancy management, contractor conversion and field employee retention factors that make up the 50 full time equivalents in 2018-19. Please indicate the share of each of these factors with regard to the 50 FTEs, as well as additional costs or savings related to each of these factors.

2018/2019 FTE

Perentage %	FTE	Reason		Savings
32%	16	Bid lag retention factors	$	622,000
48%	24	Vacancy Management	$	1,457,000
20%	10	Contractor Conversion	$	947,000
100%	**50**		**$**	**3,026,000**

In 2018-19 it is anticipated that the vacant positions will be filled to restore staffing levels in addressing safety concerns and regulatory compliance. In 2019-20 there will be vacancy management; however it will be to a lesser extent.

b) With reference to the response to Delivery 1st Round Information Request 3(a) and (b), please provide a list of FTE additions in 2018-19 [50 FTE additions compared to 2017-18] and FTE additions in 2019-20 [11 FTE additions compared to 2018-19] showing the following information for each position:

i. Indicate whether the new position was added for safety/ reliability reasons, information technology transformation and modernization reasons or other reasons (describe).

ii. Indicate and quantify any savings related to the position and where these are reflected in the test year revenue requirement.

2018-19 FTE

FTE	Position Title	Reason
1	AMI Coordinator	Modernization
10	Business Process Advisors	Information Technology Transformation
1	Collector I	Safety & Reliability
1	Commodity Manager	LOA - External
2	Customer Service Lead	Safety & Reliability
10	CSR/PDR	Safety & Reliability
1	Economic Analysis Specialist	Capital Investment
1	Instrument Tech Apprentice	Safety & Reliability
2	Labourer/Shipper Receiver	Safety & Reliability
1	Maintenance Technician I	Safety & Reliability
1	Manager, Commodity Price & Rates	Capital Investment
1	Meter Control Representative	Safety & Reliability
1	Meter Technician	Safety & Reliability
2	Operations Lead	Safety & Reliability
1	Payment Services Rep I	Safety & Reliability
1	Pipeline Welder Apprentice	Safety & Reliability
1	Purchasing Agent	Capital Investment
1	Qualilty Assurance Tech	Safety & Reliability
6	Service Technician	Safety & Reliability
2	Senior Analyst	Increasing Regulation
1	Sr Auditor	Increasing Regulation
1	Sup, Buildings	Safety & Reliability
1	Utility Operator	Safety & Reliability
50		Total Savings - $3,026,000

2019-20 FTE

FTE	Position Title	Reason
10	Business Process Advisors	Information Technology Transformation
4	Engineers	Information Technology Transformation
3	CAD Technologist	Information Technology Transformation
17		Total Savings - $1,541,000

Note: Original increase for 2019-20 was 11 FTE but this was based on draft manpower submission. Final budget indicates an increase of 17 FTE due to Contractor Conversion.

These positions result from vacancy management as well as contractor conversions. The $1.5 million in savings are reflected in the contract services category of operating and maintenance expense.

c) With the reference to the response to 1st Round Information Request 3 (g), please describe the types of applications SaskEnergy is proposing to have third party vendors host.

In March of 2018, SaskEnergy implemented Clicksoftware as the new work management software to replace an aging, unsupported legacy system. It was decided that the best approach for this project was to host the server infrastructure for the application with SaskTel. The drivers for the change to SaskTel hosting were business needs for greater reliability (up time) and availability of the application.

This model was consistent with SaskEnergy's Customer Information Systems (CIS) solution which has been hosted by a third party vendor (CGI) for the past five years. This model has proven successful to ensure a reliable, secure and easily supported environment for these large, complex solutions. To support Crown collaboration initiatives, SaskEnergy will be moving this CIS server infrastructure from CGI to SaskTel within the next 3 years.

d) Were tasks that are now to be performed by information solutions hosting applications handled by SaskEnergy employees previously?

i. If so, please explain the prior approach and why the change in approach is needed at this time.

ii. Please explain and detail the impact this change will have on the revenue requirement for the 2019-20 test year [compared to handling those applications internally].

The previous legacy work management application was hosted at SaskEnergy Place and managed by the IT Operations department. Due to the size and complexity of the new solution design, it was determined in the Distribution Work Management project which implemented the new Clicksoftware application that SaskTel was a better hosting solution. The drivers for the change to SaskTel hosting were business needs for greater reliability (up time) and availability of the application. SaskEnergy Place was found not have the redundant infrastructure needed to provide this level of service nor was it capable of accommodating upgrades.

The annual cost to hosting this infrastructure at SaskTel is $441,528 for 2018-19. Internal IT costs for the last year of support (2017) were $374,000 for Software Maintenance and $12,000 for contract analyst support.

e) Will the change to hosting services being transferred to a third party result in staffing changes for SaskEnergy? Please explain any changes that have occurred or that are planned to occur and any costs or related impacts.

Staffing will not be reduced by the third party hosting of applications. Transitioning to a services based mode reduces the pressure for additional contract resources. Over the next 5 fiscal years we anticipate contractor counts will be reduced. We are not able to provide a year over year projection as we are currently developing the plan to transition our computer room. Business priorities will drive when applications are transitioned. Staffing counts may actually rise with the need for additional vendor and service level management. Increases in staff will be offset by the reduction in contactors over time.

f) Will the change to using external hosting services result in any changes to Information System capital investments? Please detail and explain any related impacts to Information System capital investments as provided in response to 1st Round Information Request 14 (w).

As the organization transitions to a services model using third parties our information systems capital requirements will begin to decrease and be offset by increasing annual operating costs for the services. Investments in the areas of Operations Hardware Lifecycle and Lifecycle Upgrades will decrease as applications and supporting hardware are transitioned. The timing associated with these changes is dependent on organizational priorities.

g) With reference to the response to 1st Round Information Request 3 (h), please summarize cost drivers leading to the increase in Contract Services costs (26% cost increase in 2019-20 over 2017-18 actuals). Please indicate how savings from contractors transitioning to FTEs are reflected in this cost.

The primary cost drivers in the Contract services increase are as follows:

Hosting Services - $4.9 million and/or 18.8% of the cost increase

Management of Change Initiative - Contract and consulting Services - $0.7 million and/or 2.5% of the cost increase

Line Locating and Hydro Vac - $0.8 million and/or 2.9% of the cost increase

Distribution Information Systems - Contractors for Change Management - $0.4 million and/or 1.5% of the cost increase.

h) With the reference to the response to 1st Round information request 3 (j), please provide dollar values for each of the two factors that make up the 3.4% increase as indicated in the response (i.e., current contractor conversion and salary holdback program).

The dollar value for contractor conversion is approximately $1.8 million. The dollar value for the salary holdback program is approximately $1.3 million.

i) Further to (g) above, please explain if the Contract Services expense forecast is prepared based on a number of specific projects required to be completed or forecast based on a percentage increase from the previous years' actuals.

Contract Services expense is forecast primarily based on the specific projects required to be completed, standard services executed by third parties each year such as line locating, meter reading, and hydro vac, and hosting services of existing software applications currently used in SaskEnergy.

j) Please show the average net labour cost per FTE for the FTEs transferred from contractor and compare to the average net labour cost per FTE in 2017-18. Please explain the difference in relation to the response provided in 1st Round information request 3 (j).

The average net labour cost per FTE for the FTE's transferred from contractors is $105,820 compared to the average net labour cost per FTE in 2017-18 of $96,504. The trend of higher net labour cost per FTE as shown above is consistent to the response provided in 1st Round Information request 3 (j).

k) Please confirm that that as per Table 7-4 of the Review of SaskPower's 2018 Rate Application total labour costs are $365 million for 2017-18 not $437 million as stated in the response to 1st Round Information Request 3 (l). If not confirmed, please explain.

Gross labour cost excluding labour credits as per Table 7-4 of the Review of SaskPower's 2018 rate application is $437 million for 2017-18. Total labour cost including labour credits is $365 million for 2017-18.

l) With the reference to the response to 1st Round Information Request 3 (m), please provide the impact to the revenue requirement if the average labour cost of $100,677 is used for the vacancy rate adjustment.

The impact would be a lower revenue requirement of approximately $342 thousand if the average labour cost of $100,677 is used for the vacancy rate adjustment.

4. Reference: 1st Round Information Request #6 [External Services]

a) Did SaskEnergy use a tendering or Request for Proposals process to select the information hosting services provider(s)?

Yes, SaskEnergy does use a request for proposal process to select the information hosting services provider.

b) With the reference to the responses to 1st Round Information Requests 6 (e) and (f), please confirm that the Information Technology Transformation and Modernization costs of $0.7 million ($0.2 million in 2017-18 plus $0.5 million increase in 2019-20) will not extend beyond the 2019-20 test year.

Information Technology Transformation and Modernization is planned to extend beyond 2019-20. Investment in this initiative is forecasted to 2023-24. Consulting costs for this initiative will not extend beyond 2019-20 but implementation will span multiple years.

c) With the reference to the response to 1st Round Information Request 6 (f), please confirm that the depreciation study and cost of service study costs described in current application also will not extend beyond 2019-20 test year?

Confirmed. The depreciation study and cost of service study costs described in the current application will not extend beyond the 2019-20 test year.

5. Reference: 1st Round Information Request #7 [Intercompany Allocations]

a) Please explain why Health and Safety unit expenses increase from $1.020 million in 2017-18 to $1.370 million in 2018-19 and further increase to $1.897 million in 2019-20 (86% increase in 2019-20 over 2017-18 actuals). Please provide a breakdown and explanation of the costs making up the required increase.

The gradual increase in Health and Safety expenses is driven primarily driven by higher contracting and consulting expenses for both safety and awareness and the Management of Change initiative. Management of Change is about how an organization documents and controls risk associated with change. It is a process for evaluating and controlling modifications to facility design, operation, organization, and/or activities.

2017-18 - $1.020 million

Contracting driven by safety and awareness forecasted to increase by approximately $200K
Consulting driven by safety and awareness forecasted to increase by approximately $100K
Labour and Benefits forecasted to increase by $50K driven by the merger of the process safety department and the health and safety department resources.

2018-19 - $1.370 million

Contracting driven by the Management of Change initiative forecasted to increase by $465 thousand
Consulting driven by the Management of Change initiative forecasted to increase by $62 thousand

2019-20 - $1.897 million

b) Further to (a) above, please explain if the increase in costs fully cover increased safety audits and employee safety and health meetings without a need to increase the allocation of costs to the Distribution Division.

As per the response to Information Request 5 (a), the increased costs in 2019-20 are due to the Management of Change initiative. The safety audits reflect a transition to the distribution division compared to historic allocation to TransGas as stated in 1st Round Information Request 7 (a) (ii) therefore a need to increase the allocation of costs to the Distribution Division is appropriate in 2019-20.

c) With the reference to the response to 1st Round Information Request 7 (b), please explain if the costs for the new units are reallocated costs from other units or additional new costs.

i. If the costs are reallocated from other units please provide a table showing reallocation of the costs.

Please reference the 2019-20 inter-company cost allocation schedule included in Tab 10.

ii. If the costs are new incremental costs please provide rationale for the incremental costs.

No, these costs are not new incremental costs.

6. Reference: 1st Round Information Request #8 [External and Internal Recoveries]

a) In the response to 1st Round Information Request 7 (b) SaskEnergy states that the reduction in internal recoveries related to labour costs is due to the fact that less work is being completed by internal construction crews. However, in response to 1st Round Information Request 7 (b), SaskEnergy states that "[r]isk management and reliability investment drives higher activity levels as SaskEnergy is allocating resources based on priority of capital investment and with opportunities to execute being heightened internally through reallocation of capital investment, the resources must be available to meet demand." Please explain and reconcile these statements.

The information provided as stated in the question included in 1st Round Information Request 3 (c) is applicable to Distribution Engineering to which higher resourcing is engineers and computer automated drafting technologists as opposed to internal construction crews to which were referenced in 1st Round Information Request 8 (a).

7. Reference: 1stRound Information Request #9 [Transportation and Storage Expense]

a) Is the assumed 4% increase effective April 1, 2019 for both transportation and storage rates?

Yes, the increase is assumed for both transportation and storage rates.

b) Please provide the calculation of transportation and storage costs showing volumes and rates applied to arrive at the costs included in Schedule 4.1.

Calculation of 2019/20 Transporation and Storage Expense
$ in thousands

	April	May	June	July	August	September	October	November	December	January	February	March	Total
Transportation													
Contracted Demand (GJ/d)	555,000	555,000	555,000	555,000	555,000	555,000	555,000	605,000	605,000	605,000	605,000	605,000	
Demand Rates Per GJ	$ 4.8764	$ 4.8764	$ 4.8764	$ 4.8764	$ 4.8764	$ 4.8764	$ 4.8764	$ 4.8764	$ 4.8764	$ 4.8764	$ 4.8764	$ 4.8764	
Total Transportation Expense	$ 2,706	$ 2,706	$ 2,706	$ 2,706	$ 2,706	$ 2,706	$ 2,706	$ 2,950	$ 2,950	$ 2,950	$ 2,950	$ 2,950	33,696
Storage													
Contracted Firm Deliverability (GJ/d)	393,217	393,217	393,217	393,217	393,217	393,217	393,217	393,217	393,217	393,217	393,217	393,217	
Rates Contracted Withdrawal Per GJ	$ 1.9775	$ 1.9775	$ 1.9775	$ 1.9775	$ 1.9775	$ 1.9775	$ 1.9775	$ 1.9775	$ 1.9775	$ 1.9775	$ 1.9775	$ 1.9775	
	$ 778	$ 778	$ 778	$ 778	$ 778	$ 778	$ 778	$ 778	$ 778	$ 778	$ 778	$ 778	$ 9,331
Contracted Storage Volume (GJ)	23,399,000	23,399,000	23,399,000	23,399,000	23,399,000	23,399,000	23,399,000	23,399,000	23,399,000	23,399,000	23,399,000	23,399,000	
Rates Contracted Capacity per GJ	$ 0.0388	$ 0.0388	$ 0.0388	$ 0.0388	$ 0.0388	$ 0.0388	$ 0.0388	$ 0.0388	$ 0.0388	$ 0.0388	$ 0.0388	$ 0.0388	
	$ 908	$ 908	$ 908	$ 908	$ 908	$ 908	$ 908	$ 908	$ 908	$ 908	$ 908	$ 908	$ 10,892
Total Storage Expense	$ 1,685	$ 1,685	$ 1,685	$ 1,685	$ 1,685	$ 1,685	$ 1,685	$ 1,685	$ 1,685	$ 1,685	$ 1,685	$ 1,685	$ 20,223

Note: Upon preparing this response, an error in the contracted demand for transportation for April 2019 to October 2019 was noticed. The contracted demand for transportation should be 605,000 GJ/d.

8. Reference: 1st Round Information Request #10 [Depreciation Expense]

a) With the reference to the response to Delivery 1st Round Information Request 10 (d), please show how the $41.794 million was calculated using a 13-month average and compare this to the depreciation expense net of decommissioning depreciation [$43.8 million net].

The calculation of the $41.794 million is as follows:

The sum of 24 months of gross depreciation = $97.442 million / 24 = an average of $4.060 million per month X 12 months = $48.720 million

24 months of amortization of customer contributions = $13.852 million / 24 = an average of $0.577 million per month X 12 months = $6.926 million

Gross Depreciation – Amortization of Customer Contributions = $48.720 million - $6.926 million and/or $41.794 million.

The $43.839 million net is the 12 month sum of 2019-20 gross depreciation expense of $55.369 million less decommissioning depreciation of $4.347 million less amortization of customer contributions of $7.183 million which equals $43.839 million.

b) Will the depreciation study include a review of depreciation rates for decommissioning assets? Please explain. If not, please explain why not.

The depreciation study does include a review of the rates that factor in the determination of the decommissioning assets and liabilities.

c) When does SaskEnergy expect to finalize the depreciation study?

The depreciation study is expected to be completed and implemented before the end of the fiscal year.

9. Reference: 1st Round Information Request #11 [Interest Expense]

a) With reference to the response to 11(a) please provide the monthly test year forecast and actual short term and long term interest rates for the period from 2017 to 2018 to date.

Short and Long Term Debt Costs - LDC Only

	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18
SaskEnergy LDC																				
Cost of Long Term Debt (%)	n/a	n/a	3.19	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	3.24	n/a	n/a	n/a	n/a
Cost of Short Term Debt (%)	0.55	0.57	0.49	0.34	0.64	0.69	0.88	1.02	1.05	1.00	1.13	0.88	0.94	1.77	1.20	1.15	1.33	1.42	1.60	1.58
Forecast Short Term Debt Cost (%)	0.75	0.66	0.66	0.60	0.60	0.60	0.94	0.94	0.94	1.14	1.14	1.14	1.18	1.18	1.18	1.32	1.32	1.53	1.53	1.61
Forecast Long Term Debt Cost (%)	3.33	3.33	3.33	3.15	3.15	3.15	3.32	3.32	3.32	3.52	3.52	3.52	3.64	3.64	3.64	3.78	3.78	3.47	3.66	3.66

Note: In order to ensure comparablility between the actual cost of long term debt and the forecast, the actual long term debt rates as reported above reflect the rates achieved on new long term debt issues. Those months where no new long term borrowing occurred are reported as n/a.

b) Please provide the calculation of short-term interest expense similar to the information provided for long-term interest expense in Pre-ask #11.

Calculation of Short Term Interest Expense				
$ in thousands				
		Short Term Debt	Short Term Interest Rate	Short Term Interest Expense
April	2019	$ 178,516	1.98%	$ 295
May	2019	101,801	1.98%	168
June	2019	121,971	1.98%	202
July	2019	160,917	2.14%	288
August	2019	179,252	2.14%	320
September	2019	224,308	2.14%	401
October	2019	245,037	2.25%	460
November	2019	285,273	2.25%	536
December	2019	298,979	2.25%	562
January	2020	283,832	2.33%	552
February	2020	281,823	2.33%	548
March	2020	281,832	2.33%	548
Average Short Term Debt		$ 220,295		$ 4,880
Average Short Term Interest Rate			2.22%	

c) Is SaskEnergy updating the information included in Tab 14, page 3 with the information provided in the response to Delivery 1st Round Information Request 11 (c) (i)? Please explain and provide any updates or corrections as relevant.

Yes, SaskEnergy is updating the information included in Tab 14 page 3 with the information provided in the response to Delivery 1st Round Information Request 11 c (i). Please consider the information provided in Information Request 11 c (i) as the revised Tab 14 page 3 for all the short-term interest rates. Below is the revised Tab 14 page 3 schedule.

Forecasted Long and Short Term Interest Rates

Interest Rate Forecast

	Long Term Interest Rates	Short Term Interest Rates
Aug 2018	3.47%	1.53%
Sept 2018	3.47%	1.53%
Oct 2018	3.66%	1.61%
Nov 2018	3.66%	1.61%
Dec 2018	3.66%	1.61%
Jan 2019	3.78%	1.75%
Feb 2019	3.78%	1.75%
Mar 2019	3.78%	1.75%
Apr 2019	3.89%	1.98%
May 2019	3.89%	1.98%
Jun 2019	3.89%	1.98%
Jul 2019	3.96%	2.14%
Aug 2019	3.96%	2.14%
Sep 2019	3.96%	2.14%
Oct 2019	4.01%	2.25%
Nov 2019	4.01%	2.25%
Dec 2019	4.01%	2.25%
Jan 2020	4.06%	2.33%
Feb 2020	4.06%	2.33%
Mar 2020	4.06%	2.33%

10. Reference: 1st Round Information Request #12 [Tax Expense]

a) Please explain in detail the justification for including total corporate tax expense for the consolidated entity in the distribution revenue requirement.

SaskEnergy includes the consolidated entity's equity advances and total debt to calculate the distribution division corporate capital tax within its distribution division audited financial statements. SaskEnergy, the distribution division, administers the total debt on behalf of all subsidiary companies of SaskEnergy Incorporated. Within the corporate capital tax calculation, there is a considerable investment allowance and a standard exemption provided to the distribution division to offset the debt used to finance all of SaskEnergy Incorporated's subsidiary companies.

b) Please provide a corporate tax calculation table that includes only the Distribution Division paid up capital amount, including removing expenses related to loans and advances for Holdco and subsidiaries.

Calculation of Corporate Capital Tax	
	2019/20
	Forecast
Net Book Value	1,323,817
less UCC (1)	885,190
Income Tax Deduction	438,627
Retained Earnings and Equity	424,426
Loans and Advances	976,742
Interest Payable	16,056
less: Income Tax Deduction	(438,627)
Total Paid up Capital	978,597
less: Standard Exemption	(10,788)
Taxable Paid up Capital	967,809
less Investment Allowance	0
Taxable Paid up Capital	967,809
Rate	0.6%
Corporate Capital Tax Expense	5,807
Note: UCC refers to Undepreciated Capital Cost	

c) Please provide a corporate tax calculation table that provides net book value and undepreciated capital cost net of customer contributions.

Calculation of Corporate Capital Tax	
	2019/20
	Forecast
Net Book Value	1,176,753
less UCC (1)	644,727
Income Tax Deduction	532,026
Retained Earnings and Equity	548,130
Loans and Advances	1,576,054
Interest Payable	16,056
less: Income Tax Deduction	(532,026)
Total Paid up Capital	1,608,214
less: Standard Exemption	(10,788)
Taxable Paid up Capital	1,597,426
less Investment Allowance	(526,281)
Taxable Paid up Capital	1,071,145
Rate	0.6%
Corporate Capital Tax Expense	6,427
Note: UCC refers to Undepreciated Capital Cost	
***Assumes Net Book Value and Undepreciated capital cost is net of customer contributions**	

11. Reference: 1st Round Information Request #13 [Other Revenue]

a) In the response to Delivery 1st Round Information Request 13 (a), (b) and (d) SaskEnergy states that the "pipeline constraint issue at the Alberta/Saskatchewan border is expected to continue for at least two or three more years, but diminishing slightly each year." If SaskEnergy's expectation is that the pipeline constraint issue is expected to continue for at least two or three more years slightly diminishing each year why is SaskEnergy forecasting a 63% reduction in Asset Optimization revenues in 2019-20 compared to 2017-18 actual?

The extent of the Alberta border pipeline constraints is only one of several key factors that affect SaskEnergy's ability to generate Asset Optimization revenues. Other key factors are weather, market prices for natural gas, and the availability of export capacity in order to capitalize on Alberta border restrictions. SaskEnergy must consider all of these factors when forecasting Asset Optimization revenues.

b) How much of the Asset Optimization revenues accrued in summer 2017-18 versus winter months? What is the current forecast for summer/winter for 2018-19?

For 2017-18, approximately $9.0 million in Asset Optimization revenues were generated during the summer and $7.2 million during the winter months. For 2018-19, the split is projected to be approximately $12 million during the summer months and $1 million during the winter months.

c) Please provide any update on expected revenues from Asset Optimization for 2017-18 (outlook for balance of year) and 2018-19.

Revenues from Asset Optimization were $16.197 million for 2017-18 (final) and are projected to be approximately $13 million for the 2018-19 fiscal year.

d) With the reference to Delivery 1st Round Information Request responses 13 (b) (ii) and 13(c):

i. Please confirm that the contracted demand for transportation is equal to peak day requirements at 605,000 GJ's/day for 2019-20 test year.

Yes, contracted demand for delivery transportation is 605,000 GJ's/day for 2019-20.

ii. Please confirm that contracted demand for transportation of 605,000 GJ's/day impacts transportation and storage expenses.

Yes, it impacts delivery transportation expense, but not storage expense.

iii. Please elaborate on whether Asset Optimization revenues for 2017-18 would be at the same level [$16.197 million] if contracted demand in 2017-18 for transportation was 500,000 GJ's/day.

Yes, revenues from Asset Optimization for 2017-18 would have been the same if contracted delivery transportation had only been 500,000 GJ's/d for 2017-18.

12. Reference: 1st Round Information Request #14 [Capital Expenditure Program]

a) With reference to the response to Delivery 1st Round Information Request 14(a):

i. Please outline categories where forecast spending is expected to be lower than forecast and the amounts lower than forecast.

The categories are presented consistent to Tab 6 page 8 for the test year October 2017 to November 2018. Those where the forecast spending is expected to be lower and the variance are as follows:

Building/Furniture - $23.9 million

Gas Measurement - $2.7 million

Information Systems - $2.3 million

Tools/Stations/GIS - $0.6 million

Regulators - $0.2 million

System Improvements - $0.2 million

ii. Please outline whether spending in certain categories is expected to be higher than forecast, and the amounts higher than forecast.

The categories are presented consistent to Tab 6 page 8 for the test year October 2017 to November 2018. Those where the forecast spending is expected to be higher and the variance are as follows:

Customer Connections net of customer contributions - $1.8 million

Vehicles - $1.6 million

iii. Has actual capital spending been impacted by the slower growth noted for 2017-18 (discussed in response to 1st Round Information Request 14(m) or the deferral of major growth infrastructure activities (as noted in response to 1st Round Information Request 14(c)).

Actual capital spending has been primarily impacted by the assumption in the 2017-18 test year forecast that SaskEnergy will purchase SaskEnergy Place for $18.9 million. This purchase did not materialize in the 2017-18 test year and is not forecasted in the 2018-19 nor the 2019-20 fiscal year.

iv. Has actual capital spending been impacted by restraint measures? Please discuss.

No, actual capital spending has not been impacted by restraint measures. Please reference the response to question 12. a) iii above.

b) Please provide an update regarding the Capital Project Prioritization Process.

i. What steps have been taken over the last year to advance this process?

SaskEnergy continues to advance its capital prioritization process ensuring the appropriate allocation of capital is made available to address investments that have the highest value for SaskEnergy and are aligned with Crown Sector Priorities mandated by the Government of Saskatchewan. Over the past year, SaskEnergy formed a Capital Governance Committee composed of experienced enterprise focused resources that represent all areas of the company. Regularly scheduled meetings address capital prioritization in a collaborative process that leverages timing of existing investment opportunities, new investment opportunities, resource availability and cost of capital investments to both SaskEnergy and their customer.

ii. What steps are expected to be taken over the course of this year and next year to advance the process? When is the process expected to be completed and what end results are expected?

The Capital Governance Committee along with key stakeholders of capital planning and execution are awaiting the implementation of an asset planning and investment tool that will enable SaskEnergy to budget and plan the highest value capital investments. It is expected that this enterprise capital budgeting, planning and approval tool will be available in the fourth quarter of 2018-19.

iii. What benefits has the process provided to date? Specifically with regard to process efficiency, cost-effectiveness, allocation of resources and risk management.

SaskEnergy's corporate risk register, its strategic mandates, and crown sector priorities have been and continue to be at the forefront when prioritizing capital investment. This process has brought benefits such as timely reallocation of capital investment reducing lost opportunities driven by resource availability and procurement. It has advanced collaboration aligning with the strategic mandate, One Company, One Team. It has helped balance capital allocation between revenue generating investment and/or customer growth and system expansion and revenue sustaining investment and/or risk management, and reliability giving some enterprise visibility to possible expedited or deferred investments throughout the year.

iv. What have been the costs to implement this process to date? What are anticipated costs to complete and are any cost savings expected to result from the process? Please discuss.

The capital cost to implement to date is approximately $1.3 million with an approximate additional capital cost of $0.7 million required to complete the process. There is expected to be $50 thousand in cost savings that results from this process and the implementation of the enterprise capital budgeting, planning and approval solution.

There are other benefits that have not yet been quantified but drive the value of the investment and are as follows:

- Increased Efficiencies - Eliminate the need for isolated manual processes to consolidate budgeting and the effort currently required to transition everyone's view into a consolidated enterprise view. Information requirements necessary for budget development and five year forecasting are leveraged through this technological solution. This will minimize effort expended by

Financial Planning during budget development and approval cycle.

- Cost Avoidance - Defines and integrates the prioritization matrix to monitor budget allocations against performance metrics and crown sector priorities. The benefit will be more efficient spend of capital.
- Risk Avoidance - The ability to optimize the allocation of capital to maximize risk reduction and spend to investments that drive the most value for SaskEnergy.

c) With reference to the response to Delivery 1st Round Information Request 14(w):

i. Please outline what measures SaskEnergy is undertaking to address cybersecurity, and if relevant, please indicate which programs identified in the response to 1st Round Information Request 14(w) relate to cybersecurity. How much of the total spending in each year relates to addressing this issue?

In 2018, SaskEnergy undertook an activity to define and establish an Enterprise Security department responsible for the cyber and physical security aspects of the organization. Specific to cyber security, SaskEnergy maintains a robust security program incorporating administrative controls including policies, standards, incident response plans and risk assessments along with cyber focused technical security controls such as firewalls, intrusion prevention systems, security gateways for both web and email traffic, endpoint malware protection and network access control systems. All control systems provide central logging of security relevant events into our Security Event and Incident Management System (SEIM) which is monitored 24 x 7 by and external security service organization.

Security plays a role in each information systems project identified through secure design, identity and access management, vulnerability management and standards implementation. The lifecycle and IT technology initiatives identified such as Desktop Refresh and Network upgrade and expansion will also incorporate security control refresh and expansion activities within these realms. Cyber security represents 7% of overall IT spend.

ii. Please describe any needs analysis that was undertaken to support the Information Systems capital investment plan outlined in the response.

SaskEnergy reviews proposed initiatives using a project prioritization matrix in order to identify key initiatives in support of the organization's strategic plan. These initiatives are incorporated into the capital planning and are subject to additional evaluation and oversight before being initiated. Projects identified for further evaluation are incorporated into the Information Systems Project Delivery methodology which requires development of requirements, benefits, and estimated total cost of ownership. Projects are regularly reviewed and require additional approvals at each of four stage gates during the life of the project.

iii. The response notes that "SaskEnergy has identified areas of improvements to its information technology infrastructure" – please identify and describe in further detail the areas of improvement noted, the measures being undertaken or planned to be undertaken in this regard, and related costs.

SaskEnergy is undertaking a review and planned modernization of our data network. The current network design is approximately thirty years old and does not effectively support the growing needs of the organization for the movement of data and support of collaboration efforts. SaskEnergy is currently working with SaskTel to finalize a contract for network architecture services. The deliverable of this engagement will be a proposed network architecture and associated investment requirements to transition the SaskEnergy computer room to SaskTel facilities. Additional work with SaskTel is anticipated to architect upgrading of data network capacity, and implementation of network redundancy to increase resiliency. This work is being coordinated between Information Systems and SCADA to help ensure effective network connectivity for both the corporate data network and the operational control network.

iv. The response notes that initiatives were deferred in prior years and “are now becoming critical to mitigate the risks to SaskEnergy’s infrastructure.” Please outline the planned initiatives that were deferred, when the deferrals occurred, the basis for the deferral and any impacts on costs. Please indicate and describe in further detail the nature of the risks to be mitigated. What would be the impact if measures were deferred further?

Fiscal constraints over the past number of years resulted in SaskEnergy deferring upgrades to data networks and business applications including our OneWorld enterprise resource planning system, desktop operating systems, email and collaboration systems, and video conferencing infrastructure. Continued deferral of investments in key infrastructure and applications will result in unsupported systems and increased potential that key systems are unavailable for extended periods of time. As systems become unsupported the risk of cyber related breaches increases resulting in greater potential for a critical incident to occur.

v. Please explain how each of the following cost areas fit into the business strategy being developed, provide key drivers for the forecast costs, and identify any risks should the spending in the cost area not proceed as forecast: Licensing/ Hardware Infrastructure; Lifecycle Upgrades; IT Technology Initiatives; Business Technology Initiatives.

Licensing/Hardware Infrastructure – this area provides for the refresh of core server, network, storage, and end user devices and software. These items are core to SaskEnergy's ability to provide data and software services that are critical to the operation of the organization's day to day business. Forecasts are based on industry best practice refresh cycles in order to ensure devices and related operating software remain current and supported. Deferral of these expenditures will put the SaskEnergy data infrastructure in an unsupported state increasing the risk of application failures and business disruption. Unsupported software and hardware is also a much greater risk of compromise potentially exposing personal and confidential information to loss.

Lifecycle Upgrades – these costs are related to the upgrade of key business systems including email, enterprise resource planning, and billing systems. These systems must be upgraded regularly, within vendor support windows, to ensure on-going supportability from the vendor. Examples of impact include not being able to apply yearend tax updates if the payroll system is not current, no vendor support for our billing system if we are out of support, no security patches to systems when they are out of support.

IT Technology Initiatives – these are technology-based initiatives that are core to supporting changing business needs as well as mitigating legacy technology that poses security risks to the organization. Deferral of these initiatives will impact delivery of business technology initiatives and require on-going mitigation efforts related to legacy technologies.

Business Technology Initiatives – these initiatives have been identified by various business groups as initiatives that drive value in the organization. As these initiatives progress through the project delivery process requirements and benefits are more fully explored and documented in conjunction with the business owners. Approval to continue the initiative is governed by the stage gate approval process incorporated into the project delivery methodology to help ensure that the value derived by the initiative is understood and documented.

vi. Please provide a further explanation or definition for each of the cost subcategories provided in the table that outlines "Information Systems Capital Investment" (e.g., communications and collaboration infrastructure as a sub-category of Licencing/ Hardware/ Infrastructure). Please indicate why each measure is required to be undertaken at this time.

Communication and Collaboration Infrastructure: This initiative is related to the conversion of our email platform from Lotus Notes to Outlook.

DeskTop Refresh II (Windows 10): This initiative is to upgrade our corporate end user devices to Windows 10 and Office 2016 to ensure ongoing support from Microsoft.

WorkStation Support: Annual refresh cycle of end user devices to ensure current technology that supports operating systems and applications.

Operation Hardware Lifecycle (IT Infrastructure): refresh of core infrastructure including servers, storage area networks, switches, and routers.

Microsoft EA True-up: is our annual software true-up with Microsoft under the terms of our Enterprise Agreement (EA).

Lizard Tech Server Lifecycle: Upgrade of the hardware in support of the Lizard Tech software used as part of our GIS.

Hosted Contact Centre Replacement: Hosted Contact Centre (HCC) is the call management and recording product used by Customer Services in support of our distribution customers. SaskTel is our service provider and notified SaskEnergy of a change in product to provide these services. SaskEnergy is working with SaskTel to convert to the new services.

Customer Information System (CIS): This reflects the upgrade to our distribution customer billing system.

REO Upgrade: reflects lifecycle upgrade to our Report Everything Online (REO) system in support of hazard, near miss, and other health and safety related reporting.

OneWorld Upgrade: OneWorld is the corporate Enterprise Resource Planning (ERP) system that supports many core functions including Finance & Accounting, Human Resources, Procurement, Materials Management, and work order management.

Records Information Management (RIM): this initiative is the upgrade of our records management system to ensure ongoing vendor support.

FAST Upgrade: FAST is the system that supports access by Operations staff (Service Techs for example) to scanned images of customer service cards. The system provides key information in support of our customers. Upgrade is required to maintain vendor support.

Microsoft Project Server Upgrade: This initiative is to upgrade Project Server to maintain vendor support. Project Server is used by Information Systems and Engineering & Technology to manage on-going projects.

ESRI Upgrade: ESRI is the core software supporting our GIS initiatives. This initiative is to upgrade the software in order to maintain vendor support.

Longview Upgrade: Longview is the software system that supports corporate budging efforts and management. Upgrade is required to maintain vendor support.

Identity & Access Management: Is an initiative to implement a corporate identity and access management solution to support secure third party access to SaskEnergy information. Third parties include customers, contractors, first responders, and other service providers. The system will also provide the opportunity to securely streamline employee access to corporate information.

Access Database Replacements: This initiative is to replace Access databases with new solutions in order to improve supportability, usability, collaboration and security.

IT Technology Strategy: SaskEnergy is in the process of refining our Enterprise Technology Strategy to ensure on-going investment in technology that supports the corporate strategic plan. Funding has been allocated in the budget to support these initiatives as they are identified and prioritized.

Network Upgrade & Expansion: Expansion of the corporate data network is required to serve new operations facilities in the province. Work is also being done to ensure that the bandwidth to existing locations meets current business needs.

Architecture Tool: As SaskEnergy use of technology grows it becomes increasing important to effectively plan and manage the growth. The use of architecture tools will assist the efforts of Information Systems as we support the business in planning current and future initiatives.

Business Technology Strategies: Funding has been allocated to support business initiatives that arise as a result of the dynamic business environment we operate in. These funds are used to support prioritized and approved initiatives.

Customer Information Systems (CIS): This funding is to support Customer Services with required changes to the billing system that arise during the year. Examples include new gas retailers and regulatory or legal changes that impact our business.

Management of Change: This initiative is related to findings from National Energy Board reviews and audits.

Website Rebuild (Formerly known as Internet Redesign): This initiative is to upgrade SaskEnergy's external website infrastructure and provide for improved capabilities in support of customer service.

Capital Project Portfolio Management (CPPM): This initiative is implementing a vendor supported best in class system to support the prioritization and management of SaskEnergy's capital program.

GIS External Mapping and Viewing: This initiative replaces legacy software currently being used to support customer service. Additional capacity will be delivered to provide secure access to third parties to view GIS information.

Data Historian/Warehouse: This initiative is a key element in SaskEnergy's transition to more data centric decision making. Data from SaskEnergy's control systems will be made securely available via the corporate network to facilitate more effective use of the data and begin incorporating it into analytics initiatives.

Vendor Performance Management: This initiative is in support of Government of Saskatchewan requirements to more effectively manage and report on vendor performance.

Corporate Service Catalogue and Corporate White Pages: This initiative is in support of decommissioning Lotus Notes. Service currently provided in Lotus Notes will be transitioned to newer technologies and Lotus Notes will be retired.

Treasury Management System Replacement: This initiative is to upgrade or replace our existing Treasury Management solution with a more effective and vendor supported software.

ISC Land Integration (GIS): This initiative is to integrate the information received from Information Systems Corporation (ISC) into our GIS system for more efficient and effective use in support of business decision making.

vii. With respect to the response to Delivery 1st Round Information Request 14(w)(ii) please explain in further detail how these cost items relate to safety.

Distribution Work Management System supports the efforts of our Service Technicians and is used to manage both daily activities and emergency response. The system also contains working alone monitoring capabilities and emergency notification alerts that are monitored 24 hours a day. These capabilities directly support customer and employee safety.

Management of Change Solution provides a tool for all SaskEnergy employees to verify that any changes to process or equipment is appropriately reviewed and authorized by competent individuals to ensure the changes do not result in an incident.

Geographical Information Systems Solution is used to collect and maintain asset data for both the distribution and transmission pipeline systems which is critical for maintaining safe pipeline assets as well as meeting regulatory requirements. The system is also used to deliver this information to employees through a mapping interface to support safety activities such as line locating and emergency response.

Hazard Identification and Risk Assessment Project will implement a robust process to ensure SaskEnergy is regularly identifying and quantifying new and existing hazards. The process will also establish a common corporate scale of risk tolerance and ensuring adequate controls are in place to protect employees, our assets and the public.

d) With regard to safety and infrastructure renewal activities undertaken in 2016-17 and 2017-18 – were all activities completed as planned? Was all forecast spending for these activities achieved? Please explain.

In general, the work we plan is the work that gets done, however our process is to always prioritize work as it comes in, so if a very high risk item is identified, it would bump an already planned item. We also try to ensure we have additional projects "shovel ready", so design is done and ready for construction; this is in case planned work is delayed due to weather, customer outage availability, or approvals delays from external parties.

2016-17 – The year went pretty much as planned spending $22.2M of a budgeted $22.3M.

2017-18 – The spend was $28.9M to a budget of $23.9M. Most of this overage ($3.3M) can be accounted to the Saskatoon leak response in January-March. The remaining overage was due to an increase in volume in encroachment repairs in major cities (moving gas lines from under garages, decks, etc), an increased focus on these repairs started in 2017.

13. Reference: 1st Round Information Request #16 [Safety & Reliability]

a) With reference to the response to Delivery 1st Round Information Request 16(c) – does the 4.14 leak rate remove all Saskatoon leaks? If so, please provide leak rate assuming the historical levels of Saskatoon leaks [i.e., 35 leaks as noted in the response].

During the first nine months of the year, there were:

817 Total Leaks in Saskatchewan

561 Leaks in the City of Saskatoon

35 Average Leaks in the City of Saskatoon on a historical basis

Counted Leaks for the year = 817-561+35 = 291

291 leaks/70,180 km of Main x 1000 = 4.14 Leaks/1000 km of main

b) With reference to the response to Delivery 1st Round Information Request 16(f) please explain the factors that result in material changes to the number and the ratio of A, B and C leaks year to year as well as over the period from 2014 to 2016.

2014		2015		2016	
A	1685	A	547	A	1141
B	746	B	216	B	131
C	24	C	34	C	86

Many factors can go into findings.

The two biggest factors are system vintages and number of services vs length of main in areas.

System Vintages – Older systems tend to create more nuisance A and B leaks, due to time dependency and the design and construction improvements that are made over time. These leaks are not typically safety issues.

Number of Services vs Length of Main – Services have the A and B leaks where they come above ground. Underground Mains and Services are where C leaks typically are found. Mains have a significantly lower leak rate than services due to material, activity, and less components. Areas are picked on geography, so areas that are more rural, will have less leaks than urban due to higher main vs service ratio.

Other Factors – increased training on leak classification over time, equipment sensitivity, 4 year cycle areas interacting with supplemental cycle locations (these areas get surveyed more often, so when 4 year survey comes along they don't find as much as other areas).

These are the same reasons for the differences between 2014 and 2016.

c) With reference to the response provided to Delivery 1st Round Information Request 16(o), and in light of the specific risk metric noted regarding level of spending directed at safety and integrity initiatives [see Tab 7, page 1], please explain the material decrease in SaskEnergy spending on mains in 2018 [$6.7 million] compared to 2017 [$13.8 million as noted in response to 2017 Delivery Rate Application 2nd Information Request 16(i)].

2017's number included Major Growth Infrastructure, and for 2018 this category was separated into its own category, therefore not included. If this category is included, it brings 2018 spending up to $14.8M budgeted, with Mains replacement being the bulk of the difference, with a $700k increase year over year.

d) How much of service upgrade program activities and related spending is targeted on Regina? How much is targeted in Saskatoon or other areas? How does spending relate to total leaks or leak rate for these communities over the past 5 years. Please discuss.

	Quantity	Spending	5yr avg Leak Rate	2018 Leak Rate
Regina	1370	$9.5M	3.1	5
Saskatoon	1255	$7M	0.3	17
Other	775	$3.5M	3 to 8	

The above is forecasted 2018 numbers. Service Upgrade Program spending is related closely to the leak rate in communities, as project areas are mainly prioritized by leak rate. Other factors such as consequence, total number of services in an area, and spreading work across operating districts are also considered to refine the work plan. Saskatoon was added (net new) to the program in February.

14. Reference: 1st Round Information Request #17 [Net Income]

a) Please confirm that the net income forecasts for 2018-19 and 2019-20 are based on normal weather. If not confirmed, please provide weather normalized net income forecast for 2018-19 and 2019-20 and compare to 2016-17 and 2017-18 weather normalized net income provided in 1st Round Information Request 17 (c).

Confirmed. The net income forecasts for 2018-19 and 2019-20 are based on normal weather.

15. Reference: 1st Round Information Request #18 [Calculation of Ratebase]

a) Please provide the average lag days for Distribution Tolls revenues for the last five years.

The average lag days for the Distribution Toll revenues for the last five years are as follows:

2013 - 69

2014 - 71

2015 - 70

2016-17 - 71

2017-18 – 63

b) Please provide details regarding the terms and conditions for Distribution Tolls regarding the bill payment grace period and compare this to the 82.90 days used in cash working capital calculations.

The terms within the contract state that the revenues will be invoiced on the 20th day of the month following a payment term within 10 days.

16. Reference: 1st Round Information Request #19 [Capital Structure and Cost of Capital]

a) Please confirm that depreciation of decommissioning assets and accretion expense is included as part of the revenue requirement and as a result are part of delivery rates.

Confirmed. The depreciation of decommissioning assets and accretion expense are included as part of the revenue requirement and as a result are part of delivery rates.

b) Please confirm that SaskEnergy has been receiving cash from customers as part of rates since 2013 for future use [i.e., when the decommissioning actually occurs]. Does SaskEnergy maintain a separate account to accumulate cash received from customers as part of rates for depreciation of decommissioning assets and accretion expense and calculate interest on the collected amount? Please explain.

SaskEnergy does not receive cash from customers to fund its asset retirement obligation.

SaskEnergy sets up a non-cash decommissioning asset that depreciates annually to the estimated retirement date. The decommissioning depreciation is included within depreciation in the cost of service but the non-decommissioning asset is excluded from the rate base. SaskEnergy sets up a non-cash decommissioning liability to which it incurs an annual accretion expense. The accretion expense is included within interest expense in the cost of service. SaskEnergy recovers the decommissioning asset depreciation and the accretion expense from the customer but does not earn a return on the decommissioning asset as it is excluded from the rate base.

c) Please provide a table similar to Tab 14, page 1 reflecting the funded portion of the decommissioning liability [accumulated balance of depreciation of decommissioning assets and accretion expense to end of 2019-20] as no cost capital [effectively reducing debt portion of the rate base and cost of debt]. Please use Newfoundland and Labrador Hydro's

2017 GRA, Volume I, Schedule 4-II, page 4 of 9 as guidance, if required. http://www.pub.nf.ca/applications/NLH2017GRA/applications/NLH%202017%20General%20Rate%20Application%20-%20Volume%20I%20-%20Revision%205%20-%202018-07-04.PDF

The decommissioning liability is unfunded.

Local Distribution Company (LDC) Financial Summary										
2019 Delivery Rate Application Review - April 1, 2019 to March 31, 2020										
Average Rate Base	*Less Decommissioning Asset*	*Average Rate Base*		*Deemed Debt*		*Deemed Debt*		*Cost of Debt*		*Interest*
1,175,269	(85,767)	1,089,502	=	63%	=	686,386		4.58%	=	31,450
			=	37%	=	403,116		8.30%	=	33,459
						Deemed Equity		*Return on Equity*		*Net Income*
						Cost of Financing				
			63%	X	=	4.6%	=	2.9%		
			37%	X	=	8.3%	=	3.1%		
						Return on Rate Base	=	6.0%		

17. Reference 1st Round Information Request #20 [Cost of Service Study]

a) In response to Delivery 1st Round Information Request 20 (d) SaskEnergy states that a higher rate increase is required for Residential customers due primarily to lower revenues within the residential rate class. The response to Delivery 1st Round Information Request 23 (b) shows that the actual Residential class load was at the forecast level or higher. Please reconcile these two responses.

Upon further review of the Residential customer's revenues, we are mistaken; the revenues are higher in 2017-18 than forecast. The actual revenues for the Residential customer class were higher than forecast. Additional cost pressures resulted in higher than average cost increase to the residential rate class are due to infrastructure renewal, risk management and public and damage prevention activities. Essentially cost increases to this rate class have risen at a higher pace than revenue growth.

b) In response to 1st Round Information Request 20 (e) SaskEnergy states that in 2019-20 serving residential class increased to $200,587,202 from $186,648,862 in 2017-18 cost of service study. What are the key elements of increased cost to serve the Residential class in 2019-20 compared to 2017-18 test year?

The key elements include the infrastructure renewal costs associated with municipal growth plans and the associated long term growth capital to meet multiple objectives. These objectives include safe and reliable service, increased capacity, and improved asset life. Risk management programs also increase costs and include the service upgrade program, mains replacement program, station upgrades to meet regulatory requirements and asset life extensions. Public safety and damage prevention activities are also supported.

c) Please explain why there was a need to increase the allocation to Service Line Customer Functional Classification in 2019-20 compared to 2017-18 [for example, allocation of total return on rate base increase from 25.3% in 2017-18 COS to 32.5% in 2019-20 COS]. Please provide an explanation for each cost category in Schedule 2.0 of 2019-20 COS provided in Tab 12.

The cost allocated to the 'Service Line – Customer' has increased. This results from increased integrity spending associated with service lines (i.e. Saskatoon service upgrade due to curb valve issue). The classification and functionalization methods have not changed and are as per the review by Chymko Consulting.

STORAGE

SaskEnergy contracts with TransGas for storage services. As per generally accepted rate making practices, the cost of storage is allocated based on capacity.

TRANSPORT

SaskEnergy contracts with TransGas for high-pressure transmission service (delivery transport) from TEP to Town Border Stations (including larger industrial regulator stations). This is the cost for delivery transportation contracts with TransGas.

DISTRIBUTION

Town Border Stations

Town border stations, and rural regulating stations, reduce transmission pressure gas to one or more lower operating pressures suitable for distribution within a load center or to a large industrial customer within Saskatchewan. These facilities are installed on the transmission system near load centers and represent the point of entry into the distribution system as well as SaskEnergy's exclusive franchise to distribute. To ensure public safety, odorant is added through odorization equipment at the town border stations. SaskEnergy employs a Planned Preventive Maintenance program designed to ensure deliverability and reliability for the regulator stations, pressure reduction devices, line heaters, and the odorization equipment. Operating costs for the fuel gas and the costs of odorization are also included.

Feeder Mains

Feeder mains are a network that facilitates the distribution of natural gas to all customers, except those industrial customer deliveries directly from the town border station where there are no mains. These facilities consist of distribution mains operating at various pressures typically ranging from 80-275 PSIG (550-1,900 kPa), as well as the district regulator stations. These stations generally serve as an entry point to the frontage mains. SaskEnergy employs a Planned Preventive Maintenance program for all mains, key underground valves, cathodic protection, road crossing signs, and leak repairs and leak and odorization surveys. These costs are designed to ensure deliverability and reliability of the distribution network. Operating costs typically include customer requested changes to lines as well as line hits, emergency repairs and line locates.

Frontage Mains

These represent the lowest operating pressure of distribution mains. Typically, these operate at 3-60 PSIG (16-290 kPa) for urban systems and 60 to 100 psig (290-500 kPa) for rural systems and are used to serve many customers in a local area. Operating and maintenance costs are the same as described for Feeder Mains.

Service Line

A service line connects the individual customer to the feeder or frontage distribution main, and consists of the service pipe from the point of tap-off on the main to the outlet of the stopcock. Cathodic protection, leak surveys and repairs, line locates and various forms of alterations, at the discretion of SaskEnergy or by customer request, as well as line hits and repairs represent the typical operating and maintenance costs.

Customer Metering

Meters measure the volume of gas delivered by SEI to individual distribution customers within Saskatchewan. This includes the smallest meters to serve homes and businesses as well as large meters for commercial and industrial customers. The assets involved with customer metering include the cost of the meter set, inspection and original installation, plus any regulators, piping, meter brackets, volume correcting instruments and any other related devices. The labour costs of meter sampling are also included. Operating expenses primarily consist of Government inspections, meter exchanges, and any type of meter relocation. Planned maintenance of regulators, relief valves, and any other related devices occurs on a defined rotational basis over a period of years.

Meter Reading

Meter reading represents the cost of reading SEI-owned meters (excludes TransGas owned meters). This category includes AMI costs as well as the costs paid to SaskPower to perform meter reads on those meters that do not yet have AMI.

Customer Accounting

Customer accounting primarily represents customer billing and the cash receipts processes. This includes any internal and external collections activities plus the value of written off accounts, as well as late payment charges.

In Premise Service

In premise burner tip service represents the costs of responding to customer requests for service within their premise. Typical activities include all safety calls (such as odor calls, no heat, thermocouple replacements, re-lights, too much heat, and noisy equipment) and activations.

Marketing

This function includes costs for marketing related activities and general programs, as well as more general public information costs. Costs specific to Domestic Programs or specific to Commercial Programs are tracked separately and costs allocated accordingly. (See next two sub-functions.)

Domestic Programs

This function includes costs for marketing related activities and programs from Downstream Service Offering specifically targeted to customers of the Residential rate class.

Commercial Programs

This function includes costs for marketing related activities and programs from Downstream Service Offering specifically targeted to customers of the Commercial Small and Large rate classes.

Delivery Adjustments

These are predominantly for Unaccounted for Gas.

d) Please provide cost of service results [similar to the last page of cost of service study in Tab 12] using percentage allocation to Functional Classifications from 2017-18 cost of service study.

A comparison of classifications can be found on Schedule 3.0 of the cost of service study in Tab 12.

18. Reference: 1st Round Information Request #21 [Customer Bill Impacts]

a) With reference to the response to Delivery 1st Round Information Request 21 (d), please detail how the carbon tax impact is calculated [i.e., how \$0.0391/m^3 and \$0.0587/m^3 were determined using \$20/tonne and \$30/tonne carbon taxes].

The carbon tax amounts are determined by Environment and Climate Change Canada and are prescribed in the Greenhouse Gas Pollution Pricing Act. These rates are specific to marketable natural gas.

They equate to using a conversion factor of approximately 1.96 kg of CO_2e/m^3

\$20/tonne CO_2e = \$0.20/kg CO_2e x 1.96 kg CO_2e/m^3 = \$0.0391/m^3

Please see Marketable Natural Gas in Table 2 using the following link:

https://www.fin.gc.ca/activty/consult/fcpb-fsftc-eng.asp

OR

Please see Marketable Natural Gas in Schedule 2, Tables 1-5 using the following link:

http://www.parl.ca/DocumentViewer/en/42-1/bill/C-74/royal-assent

Note: The carbon tax was originally slated to be implemented at \$10/tonne effective 2018, however it has been delayed to April 1, 2019 at a rate of \$20/tonne and increasing annually by \$10/tonne to a final rate of \$50/tonne in 2023.

b) Similar to the response to 1st Round Information Request 21 (d), please provide the estimated carbon tax impact on customer bills at $50/tonne. Similar to (a) above please outline how the carbon tax impact is calculated.

	Annual Impact of Proposed Carbon Tax		
	m^3/year		($50/tonne)
Residential	2,779	-	$ 272
Commercial Small	13,074	-	$ 1,280
Commercial Large	170,147	-	$ 16,657

	Total Bills		
	m^3/year	Proposed Bill	($50/tonne)
Residential	2,779	$ 840	$ 1,112
Commercial Small	13,074	$ 2,856	$ 4,136
Commercial Large	170,147	$ 30,642	$ 47,299

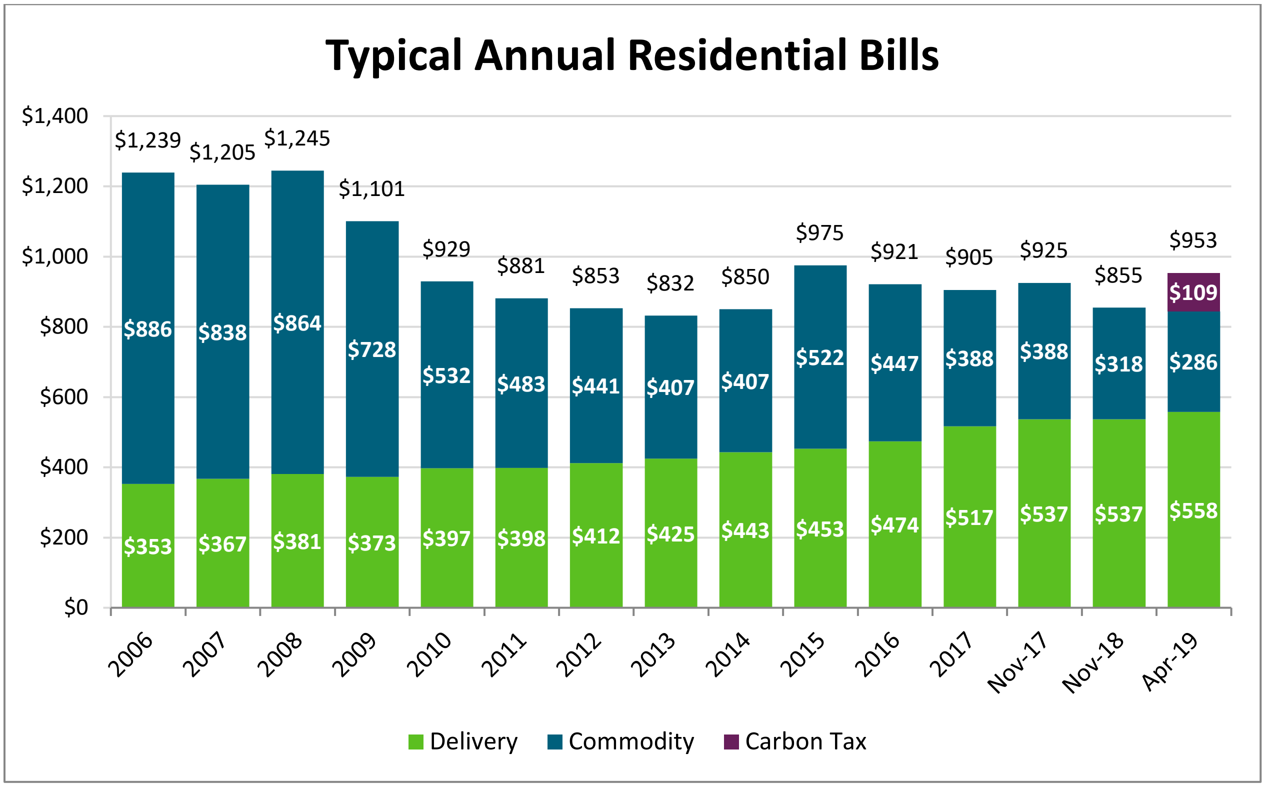
	Percentage Change		
	m^3/year		($50/tonne)
Residential	2,779	-	32%
Commercial Small	13,074	-	45%
Commercial Large	170,147	-	54%

Please see 18 (a) for how the carbon tax is calculated.

c) How will the carbon tax be addressed on customer bills?

The carbon tax will be shown as a separate line item on customer bills and will indicate the volume, rate and total cost.

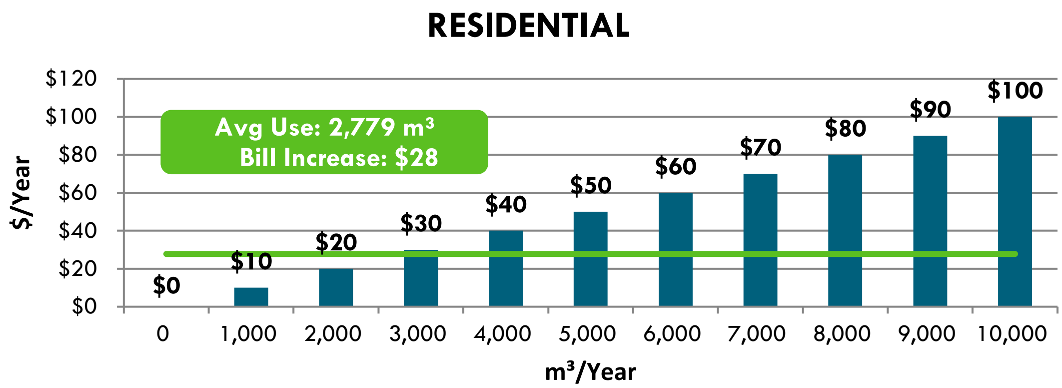
d) Please update the figure provided in response to Delivery Information Request 21(c) with the carbon tax bill impacts expected to occur April 1, 2019.

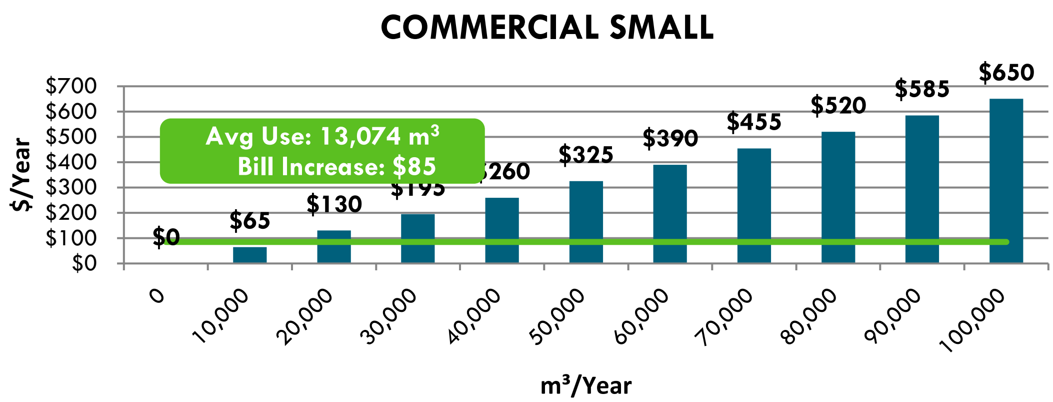


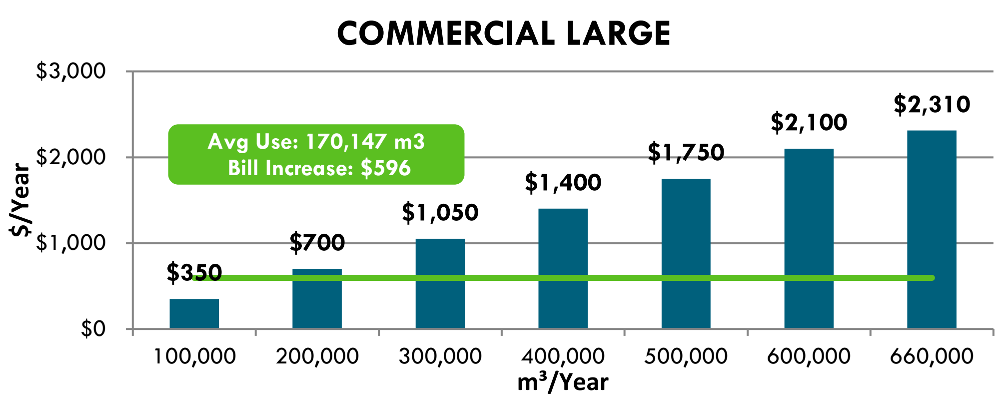
Note: The annual bill is based on an average annual consumption of 2,800 m^3.

e) Please provide a version of the figures provided in Tab 21, page 4 that includes delivery and commodity rate changes effective April 1, 2019 along with the carbon tax bill impact expected to occur April 1, 2019.

Range of Potential Annual Bill Impacts.







Note: Bill Impacts include the proposed April 1, 2019 rate changes and the proposed carbon tax.

19. Reference: 1st Round Information Request #24 [Rate Design Principles and Objectives]

a) Please describe any other impacts that would occur if the entire rate increase was applied to the BMC rather than the volumetric charge.

SaskEnergy has increased their BMC in almost every rate application over the past eleven years (with the exception of the 2013 two year application and in 2017 upon Panel's recommendation) and customer feedback has been that SaskEnergy's BMC is getting too high, particularly in the summer months when gas usage is low. Also, customers are less able to mitigate the increase through energy efficiency.

On the other hand, if the rate increase was entirely on the BMC, this would increase income stability for SaskEnergy compared to the weather dependent volumetric charge.

b) Please provide a bill impact comparison for the following:

i. Average bill impact effective April 1, 2019 for each rate class based on rate proposal included in the application for the following scenarios:

1) Average weather

Average Weather

	Total Bill Impact (%)	Annual Bill Impact ($)
Residential	-8.8%	$ (80.87)
Commercial Small	-13.0%	$ (426.22)
Commercial Large	-16.5%	$ (6,057)
Small Industrial	-20.1%	$ (29,065)

2) 10% colder than normal weather

10% Colder than Normal Weather

	Total Bill Impact (%)	Annual Bill Impact ($)
Residential	-9.0%	$ (88.96)
Commercial Small	-13.1%	$ (468.85)
Commercial Large	-16.6%	$ (6,664)
Small Industrial	-20.1%	$ (29,065)

3) 10% warmer than normal weather

10% Warmer than Normal Weather

	Total Bill Impact (%)	Annual Bill Impact ($)	
Residential	-8.5%	$	(72.78)
Commercial Small	-12.8%	$	(383.60)
Commercial Large	-16.4%	$	(5,452)
Small Industrial	-20.1%	$	(29,065)

ii. Average bill impact effective April 1, 2019 for each rate class based on rates that assume SaskEnergy's long-term objective with at least 75% of fixed customer care related costs recovered through the BMC for the following scenarios.

1) Average weather

Average Weather

	Total Bill Impact (%)	Annual Bill Impact ($)	
Residential	-9.0%	$	(82.79)
Commercial Small	-12.7%	$	(418.02)
Commercial Large	-15.9%	$	(5,833)
Small Industrial	-20.2%	$	(29,224)

2) 10% colder than normal weather

10% Colder than Normal Weather

	Total Bill Impact (%)	Annual Bill Impact ($)	
Residential	-9.5%	$	(92.99)
Commercial Small	-13.1%	$	(466.02)
Commercial Large	-16.1%	$	(6,459)
Small Industrial	-20.2%	$	(29,224)

3) 10% warmer than normal weather

10% Warmer than Normal Weather

	Total Bill Impact (%)	Annual Bill Impact ($)	
Residential	-8.5%	$	(72.59)
Commercial Small	-12.3%	$	(370.05)
Commercial Large	-15.7%	$	(5,210)
Small Industrial	-20.2%	$	(29,224)

Note: The decrease in the commodity rate skews the impact of the change from BMC to delivery charge.

20. Reference: 1st Round Information Request #26 [Heat Value]

a) With reference to Delivery 1st Round Information Request 26(a), the bill impact tables appear to have incorrect bill variances. Please provide updated and corrected versions.

There was a linking error that impacted the Total Bill Variance ($) and Total Bill Variance (%) resulting in incorrect calculations for the years 2013-2016.

Please see the corrected tables:

2013:

	Average 2013 Residential Bill by Heat Value										
Residential	Regina	Moose Jaw	Weyburn	Estevan	Swift Current	Yorkton	Melville	Saskatoon	Prince Albert	North Battleford	System Average
BMC ($)	213	213	213	213	213	213	213	213	213	213	213
Delivery ($)	193	203	178	179	203	187	185	197	195	196	195
Commodity ($)	383	403	352	354	402	371	367	391	386	388	386
Total Bill ($)	$ 789	$ 819	$ 742	$ 746	$ 817	$ 770	$ 764	$ 801	$ 794	$ 796	$ 793
Total Bill Variance ($)	$ (4)	$ 26	$ (50)	$ (47)	$ 24	$ (23)	$ (28)	$ 8	$ 1	$ 3	$ -
Total Bill Variance (%)	0%	3%	-6%	-6%	3%	-3%	-4%	1%	0%	0%	0%
Weighted Average HV (MJ/m3)	38.68	36.75	42.09	41.82	36.89	39.98	40.41	37.93	38.38	38.22	38.42

	Average 2013 Commercial Small Bill by Heat Value										
Commercial Small	Regina	Moose Jaw	Weyburn	Estevan	Swift Current	Yorkton	Melville	Saskatoon	Prince Albert	North Battleford	System Average
BMC ($)	383	383	383	383	383	383	383	383	383	383	383
Delivery ($)	805	851	743	756	848	785	783	829	827	827	816
Commodity ($)	1,823	1,926	1,681	1,711	1,920	1,777	1,772	1,876	1,872	1,873	1,846
Total Bill ($)	$ 3,011	$ 3,160	$ 2,807	$ 2,851	$ 3,152	$ 2,945	$ 2,939	$ 3,088	$ 3,083	$ 3,083	$ 3,045
Total Bill Variance ($)	$ (34)	$ 115	$ (238)	$ (194)	$ 107	$ (100)	$ (106)	$ 43	$ 38	$ 38	$ -
Total Bill Variance (%)	-1%	4%	-8%	-6%	4%	-3%	-3%	1%	1%	1%	0%
Weighted Average HV (MJ/m3)	38.68	36.75	42.09	41.82	36.89	39.98	40.41	37.93	38.38	38.22	38.42

	Average 2013 Commercial Large Bill by Heat Value										
Commercial Large	Regina	Moose Jaw	Weyburn	Estevan	Swift Current	Yorkton	Melville	Saskatoon	Prince Albert	North Battleford	System Average
BMC ($)	1,601	1,601	1,601	1,601	1,601	1,601	1,601	1,601	1,601	1,601	1,601
Delivery ($)	10,050	10,620	9,271	9,437	10,590	9,797	9,773	10,346	10,326	10,326	10,180
Commodity ($)	26,415	27,914	24,369	24,804	27,836	25,751	25,688	27,194	27,140	27,140	26,757
Total Bill ($)	$ 38,066	$ 40,134	$ 35,241	$ 35,841	$ 40,027	$ 37,149	$ 37,063	$ 39,141	$ 39,066	$ 39,067	$ 38,538
Total Bill Variance ($)	$ (472)	$ 1,596	$ (3,297)	$ (2,697)	$ 1,489	$ (1,389)	$ (1,476)	$ 602	$ 528	$ 529	$ -
Total Bill Variance (%)	-1%	4%	-9%	-7%	4%	-4%	-4%	2%	1%	1%	0%
Weighted Average HV (MJ/m3)	38.68	36.75	42.09	41.82	36.89	39.98	40.41	37.93	38.38	38.22	38.42

2014:

Residential	Regina	Moose Jaw	Weyburn	Estevan	Swift Current	Yorkton	Melville	Saskatoon	Prince Albert	North Battleford	System Average
	Average 2014 Residential Bill by Heat Value										
BMC ($)	226	226	226	226	226	226	226	226	226	226	226
Delivery ($)	207	219	190	192	216	201	200	213	209	211	209
Commodity ($)	425	450	392	395	445	414	412	437	431	434	430
Total Bill ($)	$ 858	$ 894	$ 808	$ 813	$ 887	$ 841	$ 839	$ 876	$ 867	$ 871	$ 866
Total Bill Variance ($)	$ (8)	$ 29	$ (57)	$ (53)	$ 22	$ (25)	$ (27)	$ 10	$ 1	$ 5	$ -
Total Bill Variance (%)	-1%	3%	-7%	-6%	3%	-3%	-3%	1%	0%	1%	0%
Weighted Average HV (MJ/m3)	38.82	36.72	42.14	41.80	37.10	39.92	40.05	37.75	38.31	38.06	38.36

Commercial Small	Regina	Moose Jaw	Weyburn	Estevan	Swift Current	Yorkton	Melville	Saskatoon	Prince Albert	North Battleford	System Average
	Average 2014 Commercial Small Bill by Heat Value										
BMC ($)	383	383	383	383	383	383	383	383	383	383	383
Delivery ($)	839	886	774	787	884	818	816	863	862	862	850
Commodity ($)	2,030	2,145	1,873	1,906	2,139	1,979	1,974	2,090	2,086	2,086	2,056
Total Bill ($)	$ 3,252	$ 3,415	$ 3,030	$ 3,077	$ 3,406	$ 3,180	$ 3,173	$ 3,337	$ 3,331	$ 3,331	$ 3,289
Total Bill Variance ($)	$ (37)	$ 126	$ (259)	$ (212)	$ 117	$ (109)	$ (116)	$ 47	$ 42	$ 42	$ -
Total Bill Variance (%)	-1%	4%	-8%	-6%	4%	-3%	-4%	1%	1%	1%	0%
Weighted Average HV (MJ/m3)	38.82	36.72	42.14	41.80	37.10	39.92	40.05	37.75	38.31	38.06	38.36

Commercial Large	Regina	Moose Jaw	Weyburn	Estevan	Swift Current	Yorkton	Melville	Saskatoon	Prince Albert	North Battleford	System Average
	Average 2014 Commercial Large Bill by Heat Value										
BMC ($)	1,601	1,601	1,601	1,601	1,601	1,601	1,601	1,601	1,601	1,601	1,601
Delivery ($)	10,123	10,697	9,338	9,505	10,667	9,868	9,844	10,421	10,400	10,400	10,254
Commodity ($)	29,424	31,093	27,144	27,628	31,006	28,684	28,614	30,291	30,230	30,231	29,805
Total Bill ($)	$ 41,147	$ 43,390	$ 38,083	$ 38,734	$ 43,273	$ 40,153	$ 40,059	$ 42,312	$ 42,231	$ 42,232	$ 41,659
Total Bill Variance ($)	$ (512)	$ 1,731	$ (3,576)	$ (2,925)	$ 1,614	$ (1,506)	$ (1,600)	$ 653	$ 572	$ 573	$ -
Total Bill Variance (%)	-1%	4%	-9%	-7%	4%	-4%	-4%	2%	1%	1%	0%
Weighted Average HV (MJ/m3)	38.82	36.72	42.14	41.80	37.10	39.92	40.05	37.75	38.31	38.06	38.36

2015:

Residential	Regina	Moose Jaw	Weyburn	Estevan	Swift Current	Yorkton	Melville	Saskatoon	Prince Albert	North Battleford	System Average
	Average 2015 Residential Bill by Heat Value										
BMC ($)	226	226	226	226	226	226	226	226	226	226	226
Delivery ($)	209	222	200	193	219	203	211	216	215	218	213
Commodity ($)	480	509	460	444	503	467	484	497	494	501	490
Total Bill ($)	$ 916	$ 957	$ 886	$ 863	$ 949	$ 896	$ 921	$ 940	$ 936	$ 945	$ 929
Total Bill Variance ($)	$ (14)	$ 27	$ (43)	$ (66)	$ 19	$ (33)	$ (8)	$ 10	$ 6	$ 15	$ -
Total Bill Variance (%)	-1%	3%	-5%	-7%	2%	-4%	-1%	1%	1%	2%	0%
Weighted Average HV (MJ/m3)	39.55	37.34	41.34	42.80	37.75	40.73	39.23	38.22	38.45	37.95	38.79

Commercial Small	Regina	Moose Jaw	Weyburn	Estevan	Swift Current	Yorkton	Melville	Saskatoon	Prince Albert	North Battleford	System Average
	Average 2015 Commercial Small Bill by Heat Value										
BMC ($)	383	383	383	383	383	383	383	383	383	383	383
Delivery ($)	855	904	789	803	901	834	832	881	879	879	867
Commodity ($)	2,337	2,469	2,156	2,194	2,462	2,278	2,272	2,406	2,401	2,401	2,367
Total Bill ($)	$ 3,576	$ 3,757	$ 3,328	$ 3,381	$ 3,747	$ 3,495	$ 3,488	$ 3,670	$ 3,663	$ 3,663	$ 3,617
Total Bill Variance ($)	$ (41)	$ 140	$ (289)	$ (236)	$ 130	$ (122)	$ (129)	$ 53	$ 46	$ 46	$ -
Total Bill Variance (%)	-1%	4%	-8%	-7%	4%	-3%	-4%	1%	1%	1%	0%
Weighted Average HV (MJ/m3)	39.55	37.34	41.34	42.80	37.75	40.73	39.23	38.22	38.45	37.95	38.79

Commercial Large	Regina	Moose Jaw	Weyburn	Estevan	Swift Current	Yorkton	Melville	Saskatoon	Prince Albert	North Battleford	System Average
	Average 2015 Commercial Large Bill by Heat Value										
BMC ($)	1,601	1,601	1,601	1,601	1,601	1,601	1,601	1,601	1,601	1,601	1,601
Delivery ($)	10,308	10,893	9,509	9,679	10,862	10,049	10,024	10,612	10,591	10,591	10,441
Commodity ($)	33,869	35,790	31,245	31,803	35,690	33,018	32,937	34,867	34,798	34,798	34,308
Total Bill ($)	$ 45,778	$ 48,283	$ 42,355	$ 43,082	$ 48,153	$ 44,667	$ 44,562	$ 47,080	$ 46,989	$ 46,990	$ 46,350
Total Bill Variance ($)	$ (572)	$ 1,934	$ (3,994)	$ (3,267)	$ 1,803	$ (1,682)	$ (1,788)	$ 730	$ 639	$ 640	$ -
Total Bill Variance (%)	-1%	4%	-9%	-7%	4%	-4%	-4%	2%	1%	1%	0%
Weighted Average HV (MJ/m3)	39.55	37.34	41.34	42.80	37.75	40.73	39.23	38.22	38.45	37.95	38.79

2016:

Residential	Regina	Moose Jaw	Weyburn	Estevan	Swift Current	Yorkton	Melville	Saskatoon	Prince Albert	North Battleford	System Average
	Average 2016 Residential Bill by Heat Value										
BMC ($)	251	251	251	251	251	251	251	251	251	251	251
Delivery ($)	218	226	215	196	225	207	218	222	218	223	220
Commodity ($)	403	418	398	362	415	383	402	411	404	412	406
Total Bill ($)	$ 872	$ 895	$ 865	$ 809	$ 891	$ 842	$ 870	$ 884	$ 873	$ 885	$ 877
Total Bill Variance ($)	$ (5)	$ 18	$ (12)	$ (68)	$ 14	$ (35)	$ (6)	$ 7	$ (4)	$ 8	$ -
Total Bill Variance (%)	-1%	2%	-1%	-8%	2%	-4%	-1%	1%	0%	1%	0%
Weighted Average HV (MJ/m3)	38.90	37.51	39.36	43.26	37.74	40.89	38.98	38.13	38.82	38.08	38.58

Commercial Small	Regina	Moose Jaw	Weyburn	Estevan	Swift Current	Yorkton	Melville	Saskatoon	Prince Albert	North Battleford	System Average
	Average 2016 Commercial Small Bill by Heat Value										
BMC ($)	439	439	439	439	439	439	439	439	439	439	439
Delivery ($)	872	905	862	784	899	830	871	890	874	891	880
Commodity ($)	1,927	1,999	1,905	1,733	1,987	1,833	1,923	1,966	1,931	1,969	1,943
Total Bill ($)	$ 3,238	$ 3,342	$ 3,206	$ 2,956	$ 3,325	$ 3,102	$ 3,233	$ 3,295	$ 3,244	$ 3,299	$ 3,262
Total Bill Variance ($)	$ (23)	$ 81	$ (56)	$ (305)	$ 63	$ (160)	$ (29)	$ 34	$ (17)	$ 37	$ -
Total Bill Variance (%)	-1%	2%	-2%	-9%	2%	-5%	-1%	1%	-1%	1%	0%
Weighted Average HV (MJ/m3)	38.90	37.51	39.36	43.26	37.74	40.89	38.98	38.13	38.82	38.08	38.58

Commercial Large	Regina	Moose Jaw	Weyburn	Estevan	Swift Current	Yorkton	Melville	Saskatoon	Prince Albert	North Battleford	System Average
	Average 2016 Commercial Large Bill by Heat Value										
BMC ($)	1,609	1,609	1,609	1,609	1,609	1,609	1,609	1,609	1,609	1,609	1,609
Delivery ($)	11,052	11,461	10,922	9,938	11,392	10,513	11,029	11,275	11,074	11,291	11,143
Commodity ($)	27,932	28,967	27,606	25,118	28,793	26,571	27,875	28,498	27,989	28,536	28,163
Total Bill ($)	$ 40,592	$ 42,037	$ 40,137	$ 36,665	$ 41,794	$ 38,693	$ 40,513	$ 41,382	$ 40,673	$ 41,436	$ 40,914
Total Bill Variance ($)	$ (322)	$ 1,123	$ (777)	$ (4,249)	$ 880	$ (2,221)	$ (401)	$ 468	$ (242)	$ 522	$ -
Total Bill Variance (%)	-1%	3%	-2%	-10%	2%	-5%	-1%	1%	-1%	1%	0%
Weighted Average HV (MJ/m3)	38.90	37.51	39.36	43.26	37.74	40.89	38.98	38.13	38.82	38.08	38.58

2017-18

	Average 2017-18 Residential Bill by Heat Value										
Residential	Regina	Moose Jaw	Weyburn	Estevan	Swift Current	Yorkton	Melville	Saskatoon	Prince Albert	North Battleford	System Average
BMC ($)	273	273	273	273	273	273	273	273	273	273	273
Delivery ($)	262	269	259	240	268	243	259	266	261	262	262
Commodity ($)	397	408	393	364	407	370	393	404	396	398	399
Total Bill ($)	$ 932	$ 950	$ 925	$ 877	$ 948	$ 886	$ 925	$ 943	$ 929	$ 934	$ 934
Total Bill Variance ($)	$ (2)	$ 15	$ (10)	$ (58)	$ 14	$ (48)	$ (10)	$ 9	$ (5)	$ (1)	$ -
Total Bill Variance (%)	0%	2%	-1%	-6%	1%	-5%	-1%	1%	-1%	0%	0%
Weighted Average HV (MJ/m³)	38.74	37.74	39.18	42.29	37.81	41.64	39.18	38.10	38.90	38.65	38.61

	Average 2017-18 Commercial Small Bill by Heat Value										
Commercial Small	Regina	Moose Jaw	Weyburn	Estevan	Swift Current	Yorkton	Melville	Saskatoon	Prince Albert	North Battleford	System Average
BMC ($)	462	462	462	462	462	462	462	462	462	462	462
Delivery ($)	1,045	1,073	1,034	958	1,071	973	1,034	1,063	1,041	1,048	1,049
Commodity ($)	1,901	1,952	1,880	1,742	1,948	1,769	1,880	1,933	1,893	1,906	1,908
Total Bill ($)	$ 3,409	$ 3,487	$ 3,375	$ 3,161	$ 3,481	$ 3,203	$ 3,375	$ 3,458	$ 3,396	$ 3,415	$ 3,418
Total Bill Variance ($)	$ (10)	$ 68	$ (43)	$ (257)	$ 63	$ (215)	$ (43)	$ 40	$ (22)	$ (3)	$ -
Total Bill Variance (%)	0%	2%	-1%	-8%	2%	-6%	-1%	1%	-1%	0%	0%
Weighted Average HV (MJ/m³)	38.74	37.74	39.18	42.29	37.81	41.64	39.18	38.10	38.90	38.65	38.61

	Average 2017-18 Commercial Large Bill by Heat Value										
Commercial Large	Regina	Moose Jaw	Weyburn	Estevan	Swift Current	Yorkton	Melville	Saskatoon	Prince Albert	North Battleford	System Average
BMC ($)	1,649	1,649	1,649	1,649	1,649	1,649	1,649	1,649	1,649	1,649	1,649
Delivery ($)	11,634	11,942	11,503	10,657	11,920	10,824	11,503	11,829	11,586	11,661	11,673
Commodity ($)	24,249	24,892	23,977	22,214	24,846	22,560	23,977	24,657	24,149	24,306	24,331
Total Bill ($)	$ 37,532	$ 38,483	$ 37,129	$ 34,520	$ 38,415	$ 35,033	$ 37,129	$ 38,135	$ 37,384	$ 37,615	$ 37,653
Total Bill Variance ($)	$ (121)	$ 830	$ (524)	$ (3,133)	$ 762	$ (2,620)	$ (524)	$ 482	$ (268)	$ (37)	$ -
Total Bill Variance (%)	0%	2%	-1%	-8%	2%	-7%	-1%	1%	-1%	0%	0%
Weighted Average HV (MJ/m³)	38.74	37.74	39.18	42.29	37.81	41.64	39.18	38.10	38.90	38.65	38.61

b) Please indicate the impact to delivery and commodity revenues in 2019-20 assuming a forecast heat value of 38.75 MJ/m^3. Please also provide the impact with 39.0 MJ/m^3 heat value assumption.

The impact to delivery revenues assuming a forecast heat value of 38.75 MJ/m^3 is approximately $0.97 million lower revenues than the application which contains a heat value of 38.50 MJ/m^3.

The impact to delivery and assuming a forecast heat value of 39.0 MJ/m3 is approximately $1.91 million lower than the application which contains a heat value of 38.50 MJ/m^3.

Commodity revenues would be $0.97 million lower at a heat value of 38.75 MJ/m^3 and $1.93 million lower at a heat value of 39.00 MJ/m^3.

21. Reference: 1st Round Information Request #27 [Productivity and Efficiency Update]

a) Are productivity and efficiency savings noted in Tab 25 and described in the response to Delivery 1st Round Information Request 27(b) net of costs required to implement the initiatives?

Yes, that is correct.

b) In circumstances where costs are incurred to implement the productivity and efficiency measure, is a cost-benefit assessment undertaken. Please explain.

Yes, in most instances, the economics are reviewed internally and the qualitative benefits are defined prior to execution of each productivity and/or efficiency initiative.

c) With reference to the response to 27(b) please indicate which measures are continued from prior years (and described in Tab 25). For those that are not continued from prior years please provide a further description summarizing each productivity and efficiency initiative.

Many of the initiatives continue from prior years as we continue to build out and expand on identified opportunities. Some of the initiatives that were new in 2018-19 include:

Crown Collaboration

- Crown sector land system – Land information is used by many areas in the organization and the current system is at the end of its useful life. Other Crowns also rely heavily on this information and leveraging the needs of other Crowns are expected to generate savings relative to the solution as well as from internal efficiencies with a more robust solution.
- Employee surveys – Surveys are completed by all Crowns. Having one service provider for the Crown sector will result in savings.

Business Process Changes

- Transition of contract resources – As discussed previously, savings are being realized by converting contract resources to full time equivalent resources to keep skill sets in the organization
- Reduce LDC call outs and overtime – This relates to the incremental savings related to no longer responding to no heat calls which began in 2017.
- Cathodic Protection Crossing Review Process Change – Historically, cathodic protection inspections for crossings were done on a rotational basis but are now being done based on risk assessment

Leveraging Technology

- Capital Portfolio Planning Solution – This is the system being implemented to manage capital planning.

Restated Question 27(b)

Annual Productivity and Efficiency Savings of $4.0 million are as follows:

Crown Collaboration - $0.6 million

- Crown Sector Land System leveraged by SaskEnergy, SaskPower and SaskTel - $25 thousand
- Postage, Envelopes & E-Billing Savings in collaboration with SaskPower - $350 thousand
- Employee Surveys - exploring opportunities with other crowns to realize savings on third party delivery surveys - $20 thousand
- Procurement Collaboration - $100 thousand
- Cathodic Protection upgrades – $60 thousand

Business Process Changes - $1.7 million

- Mobile Compression - $300 thousand
- Reduce LDC field operations call-outs and overtime - $400 thousand
- Overtime Policy and tracking Changes - $170 thousand
- Cathodic Protection Crossing Review Process Change - $75 thousand
- Merge of Safety and Integrity Patrols - $25 thousand
- Multi-Year Master Suppliers Agreement for Valves and Fittings - $25 thousand
- Transition of contractors to FTEs - $600 thousand
- Geo technical sponsored project work - $110 thousand
- Joint work co-ordination - $40 thousand

Leveraging Technology - $0.5 million

- Communications and Collaboration Infrastructure – Telecom Savings & Process Efficiencies - $100 thousand
- Distribution Work Management - $200 thousand
- Capital Portfolio Planning Solution Savings - $50 thousand
- Geographical Information Systems Environmental Screening Tool - $25 thousand
- Remote Video Surveillance - $30 thousand
- OT reporting and approvals - $20 thousand
- Report Everything Online (REO) Updates - $30 thousand
- Crossing Group Digital Solution - $12 thousand

Revenue Opportunities - $1.2 million

- LDC Service Charge Policy Changes - $1.0 million
- Gas Marketing Diversion Transactions - $0.2 million

d) With reference to the initiatives noted in response to Delivery 1st Round Information Request 27(b) please indicate whether any of these initiatives involve deferral of spending to future years. Please indicate which initiatives involve planned permanent spending reductions.

All initiatives noted in response to Delivery 1st Round Information Request 27 (b) involve planned permanent spending reductions.

e) With reference to Tab 25, page 7 please describe further how risk and overtime were managed in relation to the gas leaks in the city of Saskatoon in early 2018.

The Saskatoon leaks in early 2018 resulted from a failure of a type of mechanical fitting used during the installation of the gas system. Once efforts were concentrated on the area of install of these failing components, SaskEnergy was discovering up to 30 leaks per day. By utilizing the Construction, Operating and Maintenance Procedures (COMPs) the Saskatoon distribution group were able to classify leaks into a hazardous or non-hazardous. By following the COMP, we were able to successfully minimize the hazardous leaks and monitor non-hazardous leaks on a daily basis. This allowed us to schedule work based on priority through the Saskatoon issues. By monitoring the leaks, we minimized the risk to the company and by working on a priority for repair of the leaks we managed overtime by not working 24 hrs/day to fix leaks. Leaks determined to be high risk (hazardous) were addressed immediately while other leaks, which were determined to be lower risk, were monitored until a permanent repair could be made on a planned basis.

f) With reference to Tab 25, page 7 please quantify and detail the reduced overtime costs for construction and operations groups referenced.

   i. Please quantify the activities that led to the $0.95 million in savings in 2017-18 and indicate whether these were related to restraint initiatives.

Service and Maintenance Technicians planning work at the same location to reduce travel time and minimizing the time natural gas service is interrupted for customers - $0.55 million.

Service and Maintenance Technicians responding to unplanned call-outs - $0.4 million.

ii. Please quantify and describe the savings that relate to unplanned overtime vs planned overtime.

Planned overtime savings were $0.55 million and unplanned overtime savings were $0.4 million. Please reference f (i) for descriptions of the savings.

g) With respect to Tab 25, page 21 [IT Contractors Mandatory Time Off]:

i. Were the mandatory time off measures implemented in December 2016 or December 2017 included in test year forecasts those years?

No, they were not included in those test year forecasts.

ii. Is this measure more accurately characterized as a restraint measure or as an efficiency measure? Please discuss.

This is now an efficiency measure. SaskEnergy evaluated its necessary resource complement during this time of year in terms of realizing value vs. cost in information technology. It was determined that although progress was halted as stated in the productivity and efficiency update, cost savings exceed value at that time of year.

iii. Is SaskEnergy considering any similar measures for December 2018 or December 2019?

Yes, IT contractor mandatory time off will be implemented December 2018. Any measures beyond December 2018 are to be determined.

iv. Does the $260,000 in savings relate only to 2017 or does it include 2016 savings?

The savings of $260,000 is applicable to December 2016 and December 2017.

v. Has the halted progress on projects resulted in any adverse cost or other impacts? Please discuss.

No, there are no adverse cost impacts to halting progress on projects at this time of year. In most cases, these projects focused on business and technology optimization are not high risk to providing safe and reliable natural gas service to its customers.

vi. Will the conversion of contractors to FTEs impact any future application of this measure?

No, the conversion of contractors to FTE's and the benefits associated will not impact any future application of this measure.

vii. Were the mandatory contractor time off savings factored into the assessment for transitioning contractors to FTEs?

Yes, the annual total cost of contractor's inclusive of the time off savings was analyzed in comparison to the annual total cost of an FTE to determine the best option in terms of cost/value per resource.

h) Has implementation of restraint initiatives delayed implementing productivity and efficiency measures? Please discuss and quantify any deferred or foregone savings.

No, implementation of restraint initiatives has not delayed implementing productivity and efficiency measures. SaskEnergy continues to realize annual productivity and efficiency savings.

i) What are the costs of promoting paperless billing (i.e., for paid advertising, promotion through business mediums, AIRMILES promotions and promotion by Customer Service Representatives); how do these costs compare to savings in 2016-17, 2017-18 and 2018-19 as well as any future forecast savings?

The costs of promoting paperless billing have been $59,268 for paid advertising and customer incentives through business mediums in total for 2016-17, 2017-18, and 2018-19. This includes online advertising, bill inserts, and AIR MILES incentives. We have not estimated the costs related training, coaching, and offering paperless billing through Customer Service Representatives. We consider that to be within existing salary and responsibilities.

Considering the total number of customers signed up in each year, this is the value of net new annual savings that were generated each year and should continue going forward:

2016-17	$ 183,677.76
2017-18	$ 58,380.48
2018-19	$ 30,706.56 (to Nov 1, 2018)
	$ 272,764.80 in annual savings generated since April 1, 2016

Future net new annual savings should be similar to those generated for 2017/2018. The net new 2018/2019 savings are tracking to be similar to net new 2017/2018 savings. In 2016/2017 our net new savings were at a one time high because we changed our paperless billing options and removed the option to continue receiving a paper billing in addition to a paperless bill.